APPENDIX A

Carbon Dioxide Health Hazard
Information Sheet

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Carbon Dioxide
Health Hazard Information Sheet

What is carbon dioxide?

Carbon dioxide (CO_2) is a colorless, odorless, non-flammable gas that naturally occurs in the atmosphere. CO_2 is produced by body metabolism and is a normal component of exhaled breath. It also results from the burning of fossil fuels and natural sources such as volcanic eruptions. CO_2 levels in outdoor air typically range from 300 to 400 ppm (0.03% to 0.04%) but can be as high as 600-900 ppm in metropolitan areas. Although it is most commonly present as a gas, CO_2 can also exist in a solid (dry ice) form.

How are FSIS employees exposed to carbon dioxide?

The most common exposure to CO_2 for FSIS employees results from the off-gassing of CO_2 gas from the use of dry ice for chilling and packing product. Dry ice is also sometimes blended with meat product. CO_2 levels directly next to an open bin of dry ice can be as high as 11,000 to 13,000 ppm. When dry ice is used in rooms without adequate ventilation CO_2 has been measured as high as 25,000 to 30,000 ppm. However, levels at poultry plant inspection stations range from about 900 to 3,500 ppm (depending on how close the inspection station is to the dry ice use). In a few cases elevated levels, in excess of 5,000 ppm have been found at inspection stations.

CO_2 gas is also used to euthanize both poultry and swine. This process is typically fully contained and CO_2 is vented to the atmosphere (outside the building). In some cases, compressed CO_2 gas is added to plant water (eg. chillers) to make carbonic acid for pH regulation. CO_2 is denser than air and can collect in high concentrations in open pits, low lying areas and confined spaces where it can displace oxygen creating a serious health hazard.

What are the health effects of carbon dioxide?

CO_2 is considered to be minimally toxic by inhalation. The primary health effects caused by CO_2 are the result of its behavior as a simple asphyxiant. A simple asphyxiant is a gas which reduces or displaces the normal oxygen in breathing air.

Symptoms of mild CO_2 exposure may include headache and drowsiness. At higher levels, rapid breathing, confusion, increased cardiac output, elevated blood pressure and increased arrhythmias may occur.

Breathing oxygen depleted air caused by extreme CO_2 concentrations can lead to death by suffocation.

What are the symptoms of different levels of exposure?

5,000 ppm (0.5%) OSHA Permissible Exposure Limit (PEL) and ACGIH Threshold Limit Value (TLV) for 8-hour exposure

10,000 ppm (1.0%) Typically no effects, possible drowsiness

15,000 ppm (1.5%) Mild respiratory stimulation for some people

30,000 ppm (3.0%) Moderate respiratory stimulation, increased heart rate and blood pressure, ACGIH TLV-Short Term

40,000 ppm (4.0%) Immediately Dangerous to Life or Health (IDLH)

50,000 ppm (5.0%) Strong respiratory stimulation, dizziness, confusion, headache, shortness of breath

80,000 ppm (8.0%) Dimmed sight, sweating, tremor, unconsciousness, and possible death

The response to CO2 inhalation various greatly even in healthy individuals. The seriousness of the symptoms is dependent on the concentration of CO2 and the length of time a person is exposed. Since CO2 is odorless and does not cause irritation, it is considered to have poor warning properties. Fortunately, conditions from low to moderate exposures are generally reversible when a person is removed from a high CO2 environment.

Another health hazard caused by CO2 is frostbite by contact with solid CO2 (dry ice) and vapors off-gassing from dry ice. Precautions should be taken to prevent direct skin and eye contact with dry ice or with vessels/bins containing dry ice. Similar effects may occur from compressed CO2 gas as it is being released from a cylinder if it comes in contact with the skin or eyes. CO2 gas at room temperature will not injure the skin or eyes.

What OSHA standards and exposure guidelines apply?

OSHA has established a Permissible Exposure Limit (PEL) for CO2 of 5,000 parts per million (ppm) (0.5% CO2 in air) averaged over an 8-hour work day (time-weighted average or TWA.) The American Conference of Governmental Industrial Hygienists (ACGIH) recommends an 8-hour TWA Threshold Limit Value (TLV) of 5,000 ppm and a Ceiling exposure limit (not to be exceeded) of 30,000 ppm for a 10-minute period. A value of 40,000 is considered immediately dangerous to life and health (IDLH value).

The TLVs are intended to minimize the potential for asphyxiation and undue metabolic stress. The ACGIH TLV supporting document states that: “Based on the long-term exposure studies, even though the majority of references are concerned with studies on physically fit males in confined spaces, a TLV-TWA of 5,000 ppm, is recommended. This value provides a good margin of safety from asphyxiation and from undue metabolic stress provided normal amounts of oxygen are present in the inhaled air.” The TLV-STEL is based on short-term studies which showed that “concentrations of 27,600 to 39,500 ppm produced increased pulmonary ventilation rates. Therefore, a TLV-STEL of 30,000 ppm is considered appropriate.”

How are occupational exposures monitored or measured?

CO2 concentrations in air can be measured using detector tubes (for immediate short term samples) and passive indicator tubes or dosimeters (for longer TWA full or partial shift sampling). The primary OSHA method for the sampling and analysis of CO2 involves using a

gas sampling bag followed by gas chromatography or infrared spectrophotometry analysis. If you would like to arrange for CO2 monitoring at your workplace, please contact your district's Occupational Safety and Health Specialist.

What are the safety precautions protect for carbon dioxide?

Employees should receive training and be knowledgeable of the potential sources and symptoms of exposure to CO2.

If you are working near any sources of dry ice and develop any of the symptoms of exposure, move to an area of fresh air immediately, and report the incident to your supervisor. (Fresh air or oxygen is the primary remedy for CO2 exposure.

If you are pregnant consult with your supervisor and your physician about limiting exposure to CO2.

If CO2 is used to euthanize poultry or livestock ensure that you are aware of the location of the gas sources and emission vents, alarm signals and any special precautions for working in those areas.

Do not enter areas where CO2 levels exceed 20,000 ppm until ventilation has been provided to bring the concentration down to safe levels.

Do not stand directly next to open bins that contain dry ice or in vapors from these bins. Do not touch dry ice or a bin containing dry ice.

How should training for this Health Hazard Information Sheet be recorded?

Per requirements found in FSIS Directive 4791.1 Section IX, all occupational health and safety training is to be recorded using either AgLearn or FSIS form 3530-12. Training records are to include the topics covered, date, and employee name. The Agency is to retain all training records for a minimum of five years."

Resources

For more information, see the OSHA website:
https://www.osha.gov/dts/chemicalsampling/data/CH_225400.html

About the ESHG

The FSIS Environmental Safety and Health Group (ESHG) is devoted to providing a safe and healthful work environment for FSIS employees. More information on safety topics can be found on the intranet site http://www.tinyurl.com/FSIS-ESHG or by email askemployeesafety@fsis.usda.gov

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APPENDIX B

Center for Biological Diversity

References

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Via Email
July 18, 2024

Kern County Planning and Natural Resources Department
Attn: Keith Alvidrez, Planner II
2700 "M" Street, Suite 100
Bakersfield, CA 93301
CTV1EIRComments@kerncounty.com
Alvidrezk@kerncounty.com

Re: Comments on the Recirculated Draft Environmental Impact Report for Carbon TerraVault I

Dear Mr. Alvidrez:

On behalf of Center for Biological Diversity, Center on Race, Poverty & the Environment, Central California Environmental Justice Network, Central Valley Air Quality Coalition, and Sierra Club, we are writing to submit the following comments regarding the Recirculated Draft Environmental Impact Report (the Recirculated Draft EIR) for the Carbon TerraVault I Project (the CTV I Project) for carbon capture and storage (CCS) in the Elk Hills oil field. These comments are offered to ensure that Kern County (the County) complies with the California Environmental Quality Act (CEQA)[1] and CEQA Guidelines[2] in its consideration of the CTV I Project.

In addition, we submit technical expert analyses prepared by Ron Sahu, PhD, QEP, CEM (Attachment A); Dominic DiGiulio, PhD (Attachment B); and Richard Kuprewicz (Attachment C). We refer the County to these reports, both here and throughout these comments, for further discussion of the Recirculated Draft EIR's inadequacies.

These comments build upon previous comments we submitted on March 1, 2024 in response to the original December 19, 2023 Draft EIR for the CTV I Project. The Recirculated Draft EIR fails to remedy the legal deficiencies noted in our previous comments, and for those reasons and others it is inadequate under CEQA. This letter supplements and expands upon the arguments in our prior letter, but it is not intended to be exhaustive and incorporates by reference arguments made previously.

Because the County's approach to the CTV I Project has not materially changed, our requests remain the same. As in our previous letter, we urge the County not to double down on a CCS project that is designed to facilitate continued fossil fuel extraction and combustion in the County for years longer than necessary. By extending the life of the Elk Hills oil field and the existing gas plant and power plant supporting the field, and justifying the build-out of multiple new polluting facilities as future CO_2 sources, the CTV I Project will ultimately exacerbate pollution and ongoing harms to the County's frontline communities. Rather than further locking

[1] Pub. Resources Code, § 21000 *et seq*.
[2] Cal. Code Regs., tit. 14, § 15000 *et seq*. (CEQA Guidelines).

in its dependence on the fossil fuel industry, the County should adopt measures that improve health and safety protections for local communities already threatened by oil and gas operations, and invest in the transition to renewable clean energy solutions.

We also continue to urge the County to conduct a genuinely inclusive public process for the CTV I Project, which should allow for the County's many Spanish speakers to participate meaningfully. Issuing a Recirculated Draft EIR without a detailed summary of revisions made to the original draft,[3] and without notations or other clear indications of changes made to the text (e.g. underlined or italicized text), has the opposite effect and creates burdens for the public to participate in the County's decisionmaking process. Given the magnitude of the industrial activities authorized by the Project and the long-term threat these activities pose to community members' health and safety, the County's already overburdened residents deserve a reasonable opportunity to provide input on a decision that will disproportionately affect them. To that end, our organizations submitted a letter on June 21, 2024 outlining additional steps the County must take to address the flaws in its public participation process for this Project and ensure better community engagement going forward.[4] We have not received a response to that letter to date.

As with the original Draft EIR, the Recirculated Draft EIR is missing critical details about the CTV I Project and is vague throughout, making it impossible to sufficiently analyze the range of impacts due to the Project and to adopt adequate mitigation measures. The Recirculated Draft EIR therefore fails in its basic purpose of being an informational document "to provide public agencies and the public in general with detailed information about the effect that a proposed project is likely to have on the environment; to list ways in which the significant effects of such a project might be minimized; and to indicate alternatives to such a project."[5]

After carefully reviewing the Recirculated Draft EIR, we have nonetheless concluded that it suffers from the same flaws as the original Draft EIR and similarly fails in numerous respects to comply with CEQA. As explained below, the Recirculated Draft EIR violates CEQA because it fails to: (1) properly define the project description and the scope of the CTV I Project's foreseeable impacts; (2) adequately analyze and mitigate growth-inducing impacts; (3) employ appropriate Project objectives; (4) properly consider alternatives to the Project; and (5) adequately analyze and mitigate numerous foreseeable environmental impacts and cumulative impacts. As the first CCS project of its kind to undergo environmental review in California, the Recirculated Draft EIR for CTV I falls far short of establishing appropriate standards and safeguards should more of these projects move forward in the future.

For these and the additional reasons expressed below, we strongly urge the County to reject the Recirculated Draft EIR as an informational document, and to prepare and circulate a revised version that complies with CEQA.

We include a table of contents on the next page to facilitate review.

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[3] CEQA Guidelines, § 15088.5(g).
[4] Letter from undersigned groups to Kern County Planning & Natural Resources Dept., *Re: Public Participation for the Carbon TerraVault 1 (CTV 1) Carbon Capture and Storage Project* (June 21, 2024).
[5] See Pub. Resources Code, § 21061.

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I. THE RECIRCULATED DRAFT EIR'S ANALYSIS AND MITIGATION ARE BASED ON AN IMPROPER PROJECT DESCRIPTION

CEQA aims to foster greater transparency in order to ensure that decisionmakers and stakeholders are informed of potentially harmful environmental consequences of proposed projects, receive a clear and robust analysis of those consequences, and are assured that feasible mitigation is implemented. This level of transparency requires a complete understanding of the project and an analysis that encompasses the project's full scope. "Only through an accurate view of the project may outsiders and public decision-makers balance the proposal's benefits against its environmental cost, consider mitigation measures, assess the advantage of terminating the proposal . . . and weigh other alternatives in the balance."[6] Here, the County does not achieve the level of transparency required by CEQA because of an inappropriately narrow project description.

Under CEQA, a "project" is defined as the whole of an action that has the potential to cause direct or indirect physical changes to the environment.[7] A project description that omits integral components of the full project may result in an EIR that fails to disclose all the impacts of the project.[8] EIR project descriptions have been rejected as inadequate when, as is the case here, the EIR limited the scope of environmental review by artificially narrowing the project description, thus minimizing the project's impacts and undermining public review.[9]

A proper description and analysis must include "future action" that is "a reasonably foreseeable consequence of the initial project" and would "be significant in that it will likely change the scope or nature of the initial project or its environmental effects."[10] As explained below, the Recirculated Draft EIR fails to include the whole of the action in its analysis, and to analyze reasonably foreseeable and significant consequences of the CTV I Project.

The Recirculated Draft EIR's scope is too narrow because it fails to address critical components of the CTV I Project, including the Project's effect on the development of industries in Kern County that will send CO_2 for sequestration to the Elk Hills oil field, and the effect of the Project on the development of CO_2 transportation infrastructure. The narrow and vague

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[6] *County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 192.
[7] CEQA Guidelines, § 15378(a); see *Habitat Watershed Caretakers v. City of Santa Cruz* (2013) Cal.App.4th 1277, 1297.
[8] *Santiago County Water Dist. v. County of Orange* (1981) 118 Cal.App.3d 818, 829 (project description for sand and gravel mine omitted water pipelines serving project); *City of Santee v. County of San Diego* (1989) 214 Cal.App.3d 1438, 1454 (concluding that complete project description is necessary to ensure that environmental impacts of entire project are considered).
[9] See, e.g., *Rural Landowners Assn. v. City Council* (1983) 143 Cal.App.3d 1013, 1024 (EIR for city general plan amendment and rezoning that failed to describe or analyze the impacts of development that would follow annexation to the city); *County of Inyo, supra*, 71 Cal.App.3d at 193 (EIR for groundwater pumping and water export project that failed to describe or analyze groundwater exports and instead improperly sought to characterize expanding groundwater exports as a separate, ongoing project).
[10] *Laurel Heights Improvement Assn. v. Regents of Univ. of Cal* (1988) 47 Cal.3d 376, 396, as modified on denial of reh'g (Jan. 26, 1989).

description of the Project and its scope also renders the Recirculated Draft EIR informationally inadequate.

The project description states that CTV I includes "the construction and operation of an approximately 9,104-acre carbon capture and storage (CCS) facility with related capture facilities and pipeline for the initial source."[11] That "initial source," according to the Recirculated Draft EIR, would be the pre-combustion Elk Hills oil field gas, which is processed at the natural gas plant (CGP-1) facility and used at the Elk Hills power plant. The Recirculated Draft EIR goes on to say that "[n]o additional sources of CO_2 (from outside Elk Hills) or other new development are proposed for the CCS Surface Land Area or injection into the project."[12]

However, as the Recirculated Draft EIR makes clear, the "initial source" it analyzes is only the first among several sources that will inevitably send CO_2 for storage in the Project:

> Only one source has been identified and is analyzed in this EIR: existing Elk Hills field gas streams in specific locations. That operation, which is related to oilfield operations, will not provide enough captured CO_2 to produce the maximum injection capacity […] *Additional existing and new CO_2 sources, completely outside the CCS boundary of 9,104 acres, will need to be permitted and conveyed to CTV I for permanent underground storage*.[13]

The Recirculated Draft EIR also makes clear the initial source is a minor source: the storage reservoirs have the capacity to store almost 50 million metric tons (MMT) of CO_2, and the Project proponent is seeking to approve *the whole project's storage capacity* in the Recirculated Draft EIR.[14] At the same time, the Recirculated Draft EIR's analysis discloses that at a maximum, the initial source's CO_2 will add up to 203,485 tons per year (tpy) of captured CO_2.[15] Even this number is hypothetical and might in fact be much lower, as it assumes continuous operations of the power plant into the year 2045, while the Recirculated Draft EIR admits that the plant "may be forced to close sooner" due to California's fossil fuels policies.[16] Assuming a continuous injection from the initial source over the next 20 years, that source will at most provide about 4 million tons total of CO_2 for injection, leaving a minimum of about 45 million tons to be sent from other sources.[17]

It is also evident that the Project has no financial or practical viability without its future sources, beyond the initial source. The Recirculated Draft EIR explicitly admits that "[t]he life of the project is dependent on the sources permitted for injection into the storage" and on "the

[11] RDEIR, Vol. 1 at 3-1.
[12] RDEIR, Vol. 1 at 3-1.
[13] RDEIR, Vol. 1 at 3-13 (emphasis added).
[14] RDEIR, Vol. 1 at 4.8-19.
[15] RDEIR, Vol. 1 at 3-2.
[16] RDEIR, Vol. 1 at 4.8-24.
[17] Of course, as discussed in the cumulative impacts section of this comment letter below, a scenario where the vast majority of CO_2 over the life of the Project comes from the initial source is impossible, given the projections of CO_2 sourcing in the initial years of the Project and the disclosures made in the EPA Class VI permit applications as well as the California Air Resources Board (CARB) CCS Protocol certification.

ability of the project year by year to obtain CO_2 and inject at the maximum 2,210,000 million tons per year."[18] That financial dependency is also stressed in the Recirculated Draft EIR appendix titled "Envisioning a Carbon Management Park." This report states, regarding a potential carbon sequestration project, that "[f]or those wells to be cost effective, there will need to be a significant source of CO_2 – on the scale of millions of metric tons annually – available for injection."[19]

While the Recirculated Draft EIR acknowledges that other sources could be sending CO_2 to the Project, it fails to disclose all the meaningful information regarding these sources and, most importantly, it fails to disclose and analyze the sources' potential impacts.

In response to the comments that were submitted regarding the original Draft EIR for the CTV I Project released in December 2023, the County added to the Recirculated Draft EIR a new short section titled "Future Sources – Identification."[20] In this section, the County briefly describes companies that "have announced contractual relationships or interest in locating on [California Resources Corporation (CRC)] properties outside CTV I project boundary or sending CO_2 for injection at CTV I."[21] The Recirculated Draft EIR lists six broad potential sources and describes their purpose and status in a few lines. Out of the six, the Recirculated Draft EIR states that four have entered into a Carbon Dioxide Management Agreement (CDMA) with the Project's applicant CRC. The Recirculated Draft EIR notes that one of the two other potential sources is in "preliminary commercial discussions with the applicant" (the Avnos direct air capture (DAC) project). For the last one, the Elk Hills Power Plant, the Recirculated Draft EIR states that the "CalCapture project would explore capturing CO_2 emissions" from the CTV I Project's operations.[22]

In addition, the "Future Sources – Identification" section states that future sources of CO_2 will be "limited" to specific "industries" within Kern County. These "industries" include "hydrogen — green and blue," biomass carbon removal and storage (BiCRS), cement production, green steel production, oilfield field gas streams, power plants, DAC, and alternative fuel production.[23]

The Recirculated Draft EIR also includes an updated list of "cumulative projects." The list includes seven other CCS projects, two "Carbon Capture and Transport for Storage" projects, five oil and gas extraction projects (as well as the County's oil and gas ordinance), two DAC projects, and five other projects that can be potential CO_2 sources, including hydrogen and alternative fuels, and the "CTV Clean Energy Park" that is described as "multiple projects."[24]

Just as in the original Draft EIR, the Recirculated Draft EIR provides nothing more than the name, location, type, acreage, and status of each project. Most projects' status is described in the Recirculated Draft EIR as "Not submitted – media PR," some as "Application incomplete"

[18] RDEIR, Vol. 1 at 4.8-24.
[19] RDEIR, Vol. 2, App'x K.2, Envisioning A Carbon Management Business Park at 3.
[20] RDEIR, Vol. 1 at 3-13 to 3-15.
[21] RDEIR, Vol. 1 at 3-14.
[22] RDEIR, Vol. 1 at 3-15.
[23] RDEIR, Vol. 1 at 3-13.
[24] RDEIR, Vol. 1 at 3-45 to 3-47.

and some as "EIR in process."[25] The Recirculated Draft EIR does not provide any useful information on the reason why these projects are listed as cumulative, and whether they are potential CO_2 sources for the Project, or whether they are expected to have cumulative impacts for other reasons.

The Recirculated Draft EIR explains that all information regarding potential CO_2 sources has been provided by the applicant and, "if and when" any of them advances further, it will require a new environmental review process. Therefore, the Recirculated Draft EIR concludes:

> [T]hese projects are not required to be analyzed further in this EIR as approval of the project does not compel approval, nor presume completion, of any other of the contemplated projects, no applications of these other projects are pending before the county, and there is not otherwise sufficient information available to allow for meaningful environmental review of the other projects at this time.[26]

This project description violates CEQA for several reasons: first, it fails to analyze the whole of the action and presents a partial and misleading picture of the proposed development. Second, it contradicts the Recirculated Draft EIR's analysis of greenhouse gas impacts, and finally, it omits important project elements.

A. The Project Description Fails to Analyze the Whole of the Action That Has Potential to Cause Changes to the Environment.

A proper project description and analysis must include "future action" that is "a reasonably foreseeable consequence of the initial project" and would "be significant in that it will likely change the scope or nature of the initial project or its environmental effects."[27] The Recirculated Draft EIR's project description fails in both aspects.

1. The future CO_2 sources are a reasonably foreseeable consequence of the initial Project.

The Recirculated Draft EIR's representation of future sources is both lacking and misleading, leaving the document inadequate as an informational document under CEQA.

First, the new "Future Sources – Identification" section downplays the financial dependency of the Project on its CO_2 sources, and in particular the financial relationships between the Project proponent and those sources. The County inappropriately hides behind the argument that all information is provided by the applicant, and that the County is "not party" to financial agreements.[28]

The County's argument ignores the fact that the applicant *is* a party to these agreements, however, and can shed more light on the financial connections between the CTV I Project and its

[25] RDEIR, Vol. 1 at 3-45 to 3-47.
[26] RDEIR, Vol. 1 at 3-14 to 3-15.
[27] *Laurel Heights*, *supra*, 47 Cal.3d at 396.
[28] RDEIR, Vol. 1 at 3-14.

future sources. More importantly, this argument ignores publicly available information showing that the financial ties between CRC and its sources go beyond carbon management agreements. In fact, several of these projects contemplate CRC, CTV, or affiliated or subsidiary companies possessing an "equity stake" in the CO_2-sending facilities.[29] As CRC has noted publicly, these projects "play an important role within Carbon TerraVault's strategy" in developing the Project.[30] It is the County's responsibility to ensure it obtains all relevant information from CRC in order to disclose, assess, and mitigate Project impacts.

As explained above, the Recirculated Draft EIR admits that the Project is financially and practically dependent on future sources permitted for injection into the storage reservoirs.[31] The Recirculated Draft EIR's argument that "approval of the project does not […] presume completion […] of any other of the contemplated projects"[32] is thus misleading. This statement downplays the fact that the Project has no practical or financial justification without its CO_2-sending sources. These sources are not just a reasonably foreseeable consequence of the initial Project, but also an inseparable part of it, and must be properly disclosed and analyzed in the Recirculated Draft EIR.[33]

2. The future CO_2 sources are significant because they will likely change the scope or nature of the initial Project or its environmental effects, and the Recirculated Draft EIR must be revised to disclose and analyze these impacts.

An accurate and stable project description is necessary so that the lead agency and the public have enough information to "ascertain the project's environmentally significant effects,

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[29] CRC, *Carbon TerraVault Provides Second Quarter 2023 Update* (July 31, 2023), https://www.crc.com/news/news-details/2023/Carbon-TerraVault-Provides-Second-Quarter-2023-Update/default.aspx ("CTV JV and Verde are discussing CRC's potential financial participation in the RG facility, including potentially a significant equity stake") (accessed Mar. 1, 2024); CRC, *Carbon TerraVault Announces Two New Storage-Only Carbon Dioxide Management Agreements and Submission of Another Class VI Permit to the EPA* (May 1, 2023), https://www.crc.com/news/news-details/2023/Carbon-TerraVault-Announces-Two-New-Storage-Only-Carbon-Dioxide-Management-Agreements-and-Submission-of-Another-Class-VI-Permit-to-the-EPA/default.aspx ("CTV and InEnTec are discussing CRC's potential financial participation in the rDME facility, including potentially a significant equity stake").

[30] CRC, *Carbon TerraVault Provides Second Quarter 2023 Update* ("This project highlights the value proposition of our CTV Clean Energy Park and its important role within Carbon TerraVault's strategy . . . . We welcome NLCE as a trusted partner in developing and furthering California's decarbonization efforts and supporting Kern county's ambitions to become the leading carbon sequestration area in the state.").

[31] RDEIR, Vol. 1 at 4.8-24.

[32] RDEIR, Vol. 1 at 3-14 to 3-15.

[33] See also James Temple, MIT Technology Review, *The World's on the Verge of a Carbon Storage Boom* (June 12, 2024), https://www.technologyreview.com/2024/06/12/1093477/the-worlds-on-the-verge-of-a-carbon-storage-boom/ ("Carbon sequestration projects can qualify for 12 years of U.S. subsidies. If Carbon TerraVault injects half a million tons of carbon dioxide into each of the 31 wells it has applied for over that time period, the projects could secure tax credits worth more than $15.8 billion.").

assess ways of mitigating them, and consider project alternatives."[34] Information about and analysis of the sources for the CO_2 that will be injected into the CTV I Project's storage facility is crucial for this very reason. The industrial processes that will emit the CO_2, the capture technology, the CO_2 properties, and the mode of transportation to the Project all have major implications for the CTV I Project's impacts on air pollution, greenhouse gas emissions, hazardous materials, and public health, among other issues.

As just one example, whether CO_2 will be transported to the Project by trucks or pipelines, and the routes of such trucks or the locations of the pipelines, are all critical pieces of information necessary to assess the Project's potential impacts. Courts have held that an EIR for a mining operation failed as an informational document because it failed to include a "description of the facilities that will have to be constructed to deliver water to the mining operation."[35] In the same way, the Recirculated Draft EIR fails to describe the methods and facilities that will be used to send CO_2 into the CTV I Project. As discussed below, the expert Kuprewicz Report attached to these comments also finds that important information regarding pipelines is missing from the Recirculated Draft EIR.

While the Recirculated Draft EIR provides no information on the methods of CO_2 transportation from its potential sources, its project description section states that "[i]t is anticipated that diesel heavy heavy [sic] duty trucks would make 40 trips per day following the access routes designated for travel"[36] as part of the Project's operational traffic. The Recirculated Draft EIR fails to include *any* explanation as to the reason for these heavy-duty truck trips. Moreover, these trips are not mentioned or analyzed in the transportation analysis section or in the air quality section.

The "Future Sources – Identification" section added to the Recirculated Draft EIR, listing the specific "industries" that will be allowed to send CO_2 to the Project and the applicable rules, only exacerbates the serious concerns around the Project's impacts that are left undisclosed and unanalyzed.

First, it appears that instead of reducing emissions, the CTV I Project will instead incentivize new CO_2-emitting and other criteria pollutant-emitting industries, as the list is extremely broad and includes multiple industries and processes, some of which will be new to the area, some of which could be built, permitted, and operated only with a commitment to store the resulting CO_2, and all of which may create both greenhouse gas and criteria pollutant emissions.

The fact that CO_2 source facilities will now be limited to Kern County exacerbates this problem.[37] As shown above, the Project's financial viability is wholly dependent on its CO_2-sending industries. Under this new condition, existing industries that could send CO_2 but are outside the County will not be allowed to do so, thus creating an incentive for new potentially polluting development where it is not actually needed.

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[34] *Sierra Club v. City of Orange* (2008) 163 Cal.App.4th 523, 533.
[35] *Santiago County Water Dist. v. County of Orange* (1981) 118 Cal.App.3d 818, 829.
[36] RDEIR, Vol. 1 at 3-38.
[37] RDEIR, Vol. 1 at 4.11-53.

In this context, it should be noted that the new appendix added to the Recirculated Draft EIR, titled "Source Identification Memo," includes in its discussion of "Source Limitations" the following statement:

> Any additional CO_2-emitting facilities added to the CTV I carbon hub would be limited to sources that are capable of mitigating criteria pollutants from the CO_2 capture and transportation process with no net increase for existing operations.[38]

This statement limits itself to carbon capture and transportation emissions only, not addressing operational or construction emissions. Tellingly, even this limited statement, or *any* guarantee that future sources would mitigate at least part of their criteria pollutant emissions, is nowhere to be found in the project description. It is also nowhere to be found in Mitigation Measure 4.11-7, the new Measure added to the Recirculated Draft EIR that sets rules for future sources.[39] There is no guarantee that the Project will not incentivize more pollution and more CO_2 emissions. The project description must therefore disclose and analyze these potential impacts.

Second, the list of sources in the Recirculated Draft EIR highlights the risk that the Project will serve to extend the life of fossil fuel sources that will continue to operate under the guise of "zero emission" when they would have been phased out but for the Project: the sources list includes both oil field gas streams and power plants—a fossil fuel and a fossil fuel operated facility—as potential sources.[40] The recirculated cumulative projects list now includes multiple oil and gas operations as well as two existing gas power plants (in an "unknown" location).[41] The Project description fails to provide any details on the potential life extension of these heavy emitters that the Project may cause, or include any measure to safeguard against such impacts.

B. The Recirculated Draft EIR Improperly Piecemeals the Project.

The Recirculated Draft EIR engages in impermissible piecemealing under CEQA by failing to analyze, at the very least, two projects that should be analyzed as part of the CTV I Project: the Avnos DAC Project and the Hydrogen Project, which will serve as CO_2 sources.

The new "Future Sources – identification" section of the Recirculated Draft EIR lists the sources allowed to send CO_2 to the Project. The list includes both blue hydrogen and DAC projects.[42]

Both the DAC project and the blue hydrogen project were included in CRC's application to the U.S. EPA for a Class VI injection well permit: "CTV plans to source carbon dioxide initially from Lone Cypress, a proposed hydrogen plant, Elk Hills pre-combustion gas treatment, and the proposed Avnos direct air capture facility."[43] Following the application, EPA issued

[38] RDEIR, Vol. 2, App'x K.4 at 1.
[39] RDEIR, Vol. 1 at 4.11-53.
[40] RDEIR, Vol. 1 at 3-13.
[41] RDEIR, Vol. 1 at 3-45 to 3-47.
[42] RDEIR, Vol. 1 at 3-13.
[43] EPA, *Public Comments Sought on Class VI UIC Injection Well Carbon Storage Draft Permits* (Dec. 2023) at 1.

draft permits that included both sources, stating the drafts were issued following "a thorough technical review of all information submitted by CTV in its permit application, as well as the operational standards, monitoring requirements, and existing geologic setting", that was sufficient for the EPA to make a determination under the Safe Drinking Water Act.[44]

Recently, the EPA issued revised draft permits that do not include the DAC and hydrogen sources. However, CRC and CTV make clear in their letter to EPA that this removal of sources is happening in the "short-term," and that "even if the Lone Cypress and/or Avnos project does not proceed, CRC expects that over time sources of CO_2 for the 26R UIC permits will likely include hydrogen and direct air capture facilities (among other potential future sources of CO_2)."[45]

Both projects are not only a reasonably foreseeable consequence of the initial CTV I Project, but they are also dependent on the Project.[46] A DAC project, by definition, must be tied to a carbon sequestration reservoir to operate. In the same way, the blue hydrogen project relies on the CTV I Project's sequestration for its operations.[47]

At the same time, the CTV I Project is dependent on these sources. As discussed above, the Recirculated Draft EIR admits the Project's financial and functional viability is dependent on its CO_2 sources.[48] It is also evident that the Project relies on sources beyond the initial source to provide CO_2 for sequestration almost immediately after it begins operations: The Recirculated Draft EIR discloses that at a maximum, the oil field's CO_2 will add up to 203,485 tons per year (tpy) of captured CO_2.[49] But its greenhouse gas analysis projects over 300,000 tons of CO_2 to be injected by its second year—which must come from approved sources beyond the initial source.[50]

Both the DAC and Lone Cypress Hydrogen projects come with their own sets of environmental impacts related to both construction and operations, which will likely affect the CTV I Project's environmental effects. Both projects must therefore be included in the Recirculated Draft EIR, and their potential impacts must be disclosed and analyzed.

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[44] EPA, *Public Notice of Intent to Issue a Class VI Underground Injection Control Permit for Carbon TerraVault JV Storage Company Sub 1, LLC* (Dec. 2023) at 1.
[45] Letter from Travis Hurst, CRC and CTV, to David Albright, EPA Groundwater Protection Section (June 17, 2024) at 1–2.
[46] *Paulek v. Dept. of Water Res.* (2014) 231 Cal.App.4th 35.
[47] The fact that the Lone Cypress application was recently withdrawn does not change the fact that a blue hydrogen project was analyzed as a likely CO_2 source for the CTV I Project by EPA.
[48] RDEIR, Vol. 1 at 4.8-24.
[49] RDEIR, Vol. 1 at 3-2.
[50] To add sources beyond these permitted sources, the CTV I Project's proponent will have to go through a process of further application, review, and approval by EPA. RDEIR, Vol. 2, App'x E.3 – 26R Storage Project Draft Permits.

C. The Recirculated Draft EIR Contains Contradictory Statements Regarding the Project Description.

The "Future Sources – identification" list in the project description section also contradicts other sections of the Recirculated Draft EIR, particularly its greenhouse gas (GHG) analysis: The GHG analysis claims that future CO_2 sources will come from "essential but hard to decarbonize" industries.[51] As discussed in detail in our comments below on the Recirculated Draft EIR's GHG analysis, several sources in the new list cannot be categorized as "essential but hard to decarbonize" industries by any stretch of the term.[52]

As discussed more fully below in the GHG analysis section of these comments, some of the sources are not considered appropriate industries for GHG reduction purposes, as they do not have an end product or service. The term "hard to decarbonize" is also completely irrelevant to fossil fuels (like oil field gas) or to fossil fuel-based plants (like gas power plants) that appear in the list. These fuels and facilities are not "hard to decarbonize"—they are the very source of CO_2 that decarbonization efforts aim to eliminate. The Recirculated Draft EIR must be revised to provide a coherent and consistent description and analysis of future CO_2 sources.

D. The Recirculated Draft EIR's Project Description Fails to Disclose Important Project Elements.

The Recirculated Draft EIR is missing important project description information. The original Draft EIR included aerial photos and drawings showing the site layout and the potential locations for the Project's amine units. In the Recirculated Draft, the County inexplicably removed three figures: Figure 3-5 that showed Phase 1 Amine Unit and Possible Relocation Sites for Phase 2 Amine Unit, and Figures 3-6 and 3-7 that showed the existing and new components of each of the two sites in the 26R reservoir. The project description is now missing important information on the location and layout of its components that must be included in a revised draft to properly serve as an informational document and provide the public with sufficient details.[53]

E. The Recirculated Draft EIR Fails to Disclose or Address the Impacts of CRC's Merger with Aera Energy.

As is clear from public statements from CRC and other significant media coverage throughout 2024,[54] the CTV I Project proponent has now successfully facilitated a merger that has resulted in the combination of CRC and Aera Energy LLC (Aera).[55] CRC now owns Aera

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[51] RDEIR, Vol. 1 at 4.8-26.
[52] See section V.B.1.b of this comment letter.
[53] *Laurel Heights, supra*, 47 Cal.3d at 405.
[54] See, e.g., Fassler, Joe, DeSmog, *As CRC Prepares to Buy Aera, New Law to Stem Orphan Wells Faces its First Test* (Mar. 18, 2024), https://www.desmog.com/2024/03/18/california-resources-corporation-aera-energy-merger-orphan-idle-wells-ab-1167/; Cantu, Aaron, Capital & Main, *Will California's Largest Oil Well Owner Get a Pass on Paying to Clean Up Its Mess?* (June 18, 2024), https://capitalandmain.com/will-californias-largest-oil-well-owner-get-a-pass-on-paying-to-clean-up-its-mess.
[55] Securities and Exchange Com., CRC, Form 8-K (June 28, 2024), Ex. 10.2, Agreement and Plan of Merger (Feb. 7, 2024).

and its significant number of wells and pore space in California, making the combined entity the largest oil and gas company in the state.[56]

This merger is clearly "significant in that it will likely change the scope or nature of the initial project or its environmental effects."[57] As CRC publicly states, the acquisition of Aera "doubles CRC's premium CO_2 pore space in the San Joaquin Basin."[58] According to a news release, CRC is expecting to expand its carbon management business "through the addition of surface acreage and rights, and significant new carbon dioxide (CO) pore space to enable future carbon capture and sequestration (CCS) development."[59] This new storage potential at the Project site is clearly viewed by CRC as a financial opportunity that can generate significant profits.[60] CRC further states it expects to obtain a pending EPA Class VI permit and apply for additional similar projects in oil fields around CTV I.[61] CRC thus appears to view CTV I as part of a larger project, stating that it "will have the potential to nearly double its injection rate capacity near CTV I, creating a premier 'decarbonization hub' for CO_2 storage."[62]

The County's failure to address the merger and its impacts on CTV I in this Recirculated Draft EIR, despite information being publicly available regarding the merger throughout 2024, violates CEQA and renders the document deficient. The Recirculated Draft EIR should disclose and analyze this potential expansion of the Project's scope and its impacts, particularly as part of the project description analysis.

II. THE RECIRCULATED DRAFT EIR FAILS TO ANALYZE GROWTH-INDUCING IMPACTS

CEQA requires the Recirculated Draft EIR to describe growth-inducing impacts of the CTV I Project,[63] including ways in which the Project could directly or indirectly foster economic growth that could lead to an adverse physical change to the environment.[64]

In a one-paragraph discussion, the Recirculated Draft EIR explains that because Project operation would include five regular full-time employees, with five potential additional maintenance employees, the Project "would not result in a substantial influx of people" and "is not likely to induce any growth within Kern County."[65]

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[56] CRC, Press Release, *California Resources Corporation to Combine with Aera Energy* (Feb. 7, 2024), https://www.crc.com/news/news-details/2024/California-Resources-Corporation-to-Combine-with-Aera-Energy/default.aspx.
[57] *Laurel Heights, supra*, 47 Cal.3d at 396.
[58] CRC and Aera, Press Release, *Expanding Our Leading Energy Platform* (Feb. 24, 2023) at 6.
[59] CRC and Aera, Press Release, *California Resources Corporation to Combine with Aera Energy* at 2.
[60] *Id.* at 6 ("Incremental pore space has the potential to generate significant EBITDA, ranging from $70MM to $180MM.").
[61] *Id.*
[62] *Id.*
[63] Pub. Resources Code, § 21100(b)(5); CEQA Guidelines, § 15126(d).
[64] CEQA Guidelines, §§ 15126.2(d), 15064(e); *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1205.
[65] RDEIR, Vol. 1 at 5-8.

By focusing on the projected number of employees in the CTV I Project alone, the Recirculated Draft EIR ignores the requirement to discuss the ways in which a proposed project could foster *economic growth*, not only population growth, directly or indirectly.[66] Clearly, as described above, the CTV I Project is just the first step in a much larger development for which CTV has already signed multiple CDMAs. In addition, the storage capacity proposed for approval can accommodate many more metric tons of CO_2 than the Recirculated Draft EIR analyzes. Further economic growth from the Project is clearly what the Project proponents and the County envision, and it should be analyzed.

Moreover, a report prepared for the County to analyze the potential fiscal and economic benefits of a carbon management park found significant economic growth from such a park development: The potential volume ("output") associated with the carbon management park and related offsite activities is projected in the report to range from $4.5 billion to $6.9 billion per year. Regarding employment, the report finds that, at full buildout, the park and related offsite activities would directly and indirectly support 13,500 to 22,000 permanent jobs.[67] While this report does not directly analyze the specific projects envisioned for the Elk Hills oil field, it shows the potential economic growth that needs to be discussed under a proper growth-inducing analysis.

III. THE RECIRCULATED DRAFT EIR FAILS TO PROVIDE ADEQUATE PROJECT OBJECTIVES

The Recirculated Draft EIR does not provide an adequate set of project objectives. The document articulates no purpose, need, or objectives for the CTV I Project independent of a list of "the applicant's objectives" for the Project.[68] Because, as discussed below, the integrity and validity of an alternatives analysis depends in significant part on the articulation and assessment of the lead agency's project objectives, an EIR that lacks an adequate statement of those objectives will not be in compliance with CEQA. This deficiency is compounded by the likelihood that the Project will both attract and incentivize the construction of new CO_2-generating facilities instead of focusing on reducing and sequestering CO_2 emissions from existing facilities, and also be used as a rationale to extend the life of existing fossil-fuel infrastructure whose utility otherwise may cease sooner.

Here, the Recirculated Draft EIR states:

The following are the applicant's project objectives:

- Construct and operate a permanent underground storage facility to develop and use existing CO_2 storage capacity at Elk Hills in an economically feasible manner.

[66] CEQA Guidelines, § 15126.2(e).
[67] The Natelson Dale Group Inc., *Analysis of Potential Fiscal and Economic Benefits of Kern County Carbon Management Industry* (Apr. 4, 2023) at 6, https://psbweb.kerncounty.com/planning pdfs/cmbp/CMBP_Potential_Fiscal_Economic_Benefit_Analysis.pdf.
[68] RDEIR, Vol. 1 at 1-5, 3-7, 6-7 to 6-8.

- Contribute to CRC's adopted goals of Full-Scope Net Zero emissions for Scope 1 (direct greenhouse gas emissions), Scope 2 (indirect greenhouse gas emissions associated with the purchase of electricity/steam/heat/cooling) and Scope 3 (all other indirect greenhouse gas emissions resulting from the company's business operations) emissions by 2045 by capturing and storing CO_2 emissions from CRC's Elk Hills field gas operations.
- Support California's Executive Order B-55-18, for California to achieve carbon neutrality by 2045 and net negative emissions thereafter.
- Site and design the project in an environmentally responsible manner consistent with current Kern County and California guidelines.
- Promote economic development and bring living-wage jobs to Kern County.[69]

The Recirculated Draft EIR articulates no purpose, need, or objectives for the CTV I Project independent of this list of "the applicant's objectives" for the Project. But without a purpose, need, and objectives adopted by the lead agency, the Recirculated Draft EIR cannot meaningfully assess impacts and develop or compare a reasonable range of alternatives to the proposed Project.[70]

Finally, the Project's objectives were revised in the Recirculated Draft EIR such that the Project's goal of contributing to CRC's "adopted goals of Full-Scope Net Zero emissions" is now qualified by the sentence "by capturing and storing CO_2 emissions from CRC's Elk Hills field gas operations."[71] This suggests that the Project will intentionally serve to extend the life of fossil fuels—making that a specific objective of the project, in tension with objectives that support carbon emissions reduction. Because the applicant operates the oil field that will be a major source of CO_2 for the storage facility, and this facility appears to be designed at least in part to enable the oil field operations to continue to emit Scope 1, 2, and 3 emissions and to facilitate the development and operation of new GHG-emitting facilities, working against state carbon neutrality goals, it is particularly important to scrutinize the project objectives and ensure they reflect public agency goals.

IV. THE RECIRCULATED DRAFT EIR FAILS TO ANALYZE ADEQUATE ALTERNATIVES

The Recirculated Draft EIR is also unlawful for failing to properly put forward, describe, and analyze a reasonable range of alternatives. Under CEQA, a proper analysis of alternatives is essential to comply with the Act's mandate that significant environmental impacts be avoided or

[69] RDEIR, Vol. 1 at 1-5, 3-7, 6-7 to 6-8.
[70] *North Coast Rivers Alliance v. Kawamura* (2015) 243 Cal.App.4th 647, 666 (citing Pub. Resources Code, §21001(g) (internal quotation omitted)) ("[t]he process of selecting the alternatives to be included in the EIR begins with establishment of project objectives by the lead agency"); see also CEQA Guidelines, §15124(b) (stating an EIR requires a statement of the objectives sought by the proposed project).
[71] RDEIR, Vol. 1 at 3-7.

substantially lessened where feasible.[72] The analysis of alternatives lies at the "core of an EIR,"[73] and an EIR must "ensure that all reasonable alternatives to proposed projects are thoroughly assessed by the responsible official."[74]

The purpose of the requirement to contemplate alternatives is to identify ways to mitigate or avoid the significant effects of a project.[75] "[A]n agency may not approve a proposed project if feasible alternatives exist that would substantially lessen its significant environmental effects."[76] The alternatives discussion must be "meaningful" and must "contain analysis sufficient to allow informed decision making."[77] The alternatives analysis is critical to the integrity of an EIR.[78] An EIR must "ensure that all reasonable alternatives to proposed projects are thoroughly assessed by the responsible official."[79] An alternatives analysis under CEQA must focus on potentially feasible alternatives to the project, even if these alternatives would impede to some degree the attainment of project objectives, or would be more costly.[80]

As explained below, the Recirculated Draft EIR's alternatives discussion fails to comply with CEQA. The alternatives discussion is flawed for at least seven reasons: (1) it relies on an inadequate project description; (2) it relies on an inadequate set of project objectives; (3) it relies on an inadequate understanding of the Project's own impacts; (4) it fails to consider a reasonable range of alternatives; (5) it fails to properly or coherently discuss the "no project" alternative and compare it to the Project; (6) it fails to meaningfully describe or analyze the action alternatives it considers; and (7) it fails to provide substantial evidence to support its comparisons of alternatives to the proposed Project. The Recirculated Draft EIR must be revised to properly analyze project alternatives, as required by CEQA.

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[72] Pub. Resources Code, § 21002; CEQA Guidelines, §§ 15002(a)(3), 15021(a)(2), 15126(d); *Citizens for Quality Growth v. City of Mount Shasta* (1988) 198 Cal.App.3d 433, 443–45.
[73] *Citizens of Goleta Valley v. Bd. of Supervisors* (1990) 52 Cal.3d 553, 564.
[74] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 735; see also Pub. Resources Code, § 21002.1(a).
[75] Pub. Resources Code, § 21002.1.
[76] *Save Panoche Valley v. San Benito County* (2013) 217 Cal.App.4th 503, 52 (citations omitted); see also Pub. Resources Code, §21081(a); CEQA Guidelines, §15091(a)(3); *Cal. Native Plant Society v. City of Santa Cruz* (2009) 177 Cal.App.4th 957, 1002.
[77] *Laurel Heights*, *supra*, 47 Cal.3d at 403–04.
[78] *In re Bay-Delta Programmatic Envtl. Impact Report Coordinated Proceedings*, 43 Cal.4th 1143, 1162 (2008) ("The EIR is the heart of CEQA, and the mitigation and alternatives discussion forms the core of the EIR.").
[79] *San Joaquin Raptor/Wildlife Rescue Center*, *supra*, 27 Cal.App.4th at 735; see also Pub. Resources Code, § 21002.1(a).
[80] CEQA Guidelines, § 15126.6(b), (f); see also Pub. Resources Code, § 21102.1(a) ("The purpose of an environmental impact report is to identify the significant effects on the environment of a project, to identify alternatives to the project, and to indicate the manner in which those significant effects can be mitigated or avoided.").

A. The Recirculated Draft EIR Cannot Properly Consider Alternatives Without an Adequate Project Description, Adequate Description of the Lead Agency's Project Objectives, and Adequate Analysis of Project Impacts.

The Recirculated Draft EIR's alternatives analysis fails in three threshold ways: it is not based on an adequate project description, it does not articulate a public purpose and need for the Project, and it does not describe, assess, or analyze impacts properly. These deficiencies render the alternatives analysis inadequate.

First, the Recirculated Draft EIR's alternatives analysis is flawed because it is not based on a stable, accurate project description. As demonstrated above, the Recirculated Draft EIR's analysis and mitigation are based on an improper project description that understates and misstates the CTV I Project's scope, and omits integral components of the full Project. Without a proper project description, it is not possible to effectively develop alternatives or compare Project impacts with alternatives in a way that is coherent and supported by substantial evidence.

Second, without a proper description of the Project's purpose and need and a set of project objectives adopted by the lead agency, it is impossible to adequately assess alternatives to the Project in a way that complies with CEQA.

A proper statement of the lead agency's project objectives is essential to the development of an adequate alternatives analysis. This principle is apparent throughout the Guidelines and case law. For example, "[t]he process of selecting the alternatives to be included in the EIR begins with establishment of project objectives by the lead agency."[81] The Recirculated Draft EIR must include "[a] clearly written statement of objectives," as this will guide the County in developing a reasonable range of alternatives.[82] CEQA Guidelines section 15124(b) notes that a "clearly written statement of objectives will help the lead agency develop a reasonable range of alternatives to evaluate in the EIR and will aid the decision makers in preparing findings or a statement of overriding considerations, if necessary."[83] That statement of the *lead agency's* objectives, in informing the *lead agency's* reasonable range of alternatives to a proposed project, cannot simply be delegated to a project proponent.

Moreover, "[a] lead agency may not give a project's purpose an artificially narrow definition. An agency 'may structure its EIR alternative analysis around a reasonable definition of underlying purpose and need not study alternatives that cannot achieve that basic goal. For example, if the purpose of the project is to build an oceanfront resort hotel or a waterfront aquarium [citation], a lead agency need not consider inland locations.'"[84] This principle requires, again, that the lead agency take responsibility for articulating the project purpose and need as well as the project objectives.

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[81] *North Coast Rivers Alliance*, *supra*, 243 Cal. App.4th at 666 (citing Pub. Resources Code, §21001(g) (internal quotation omitted)); see also CEQA Guidelines, §15124(b) (stating an EIR requires a statement of the objectives sought by the proposed project).
[82] CEQA Guidelines, § 15124(b).
[83] CEQA Guidelines, § 15124(b).
[84] *North Coast Rivers Alliance*, *supra*, 243 Cal.App.4th at 668 (citing *Bay–Delta*, *supra*, 43 Cal.4th at 1166 [internal citations omitted]).

Here, as noted above, the Recirculated Draft EIR articulates no purpose, need, or objectives for the Project independent of a list of "the applicant's objectives" for the Project.[85] The Recirculated Draft EIR contains no further discussion of purpose, need, or objectives beyond this list. But, as reflected in the case law and Guidelines,[86] it is not possible for a lead agency to meaningfully undertake an independent evaluation of alternatives if the agency uncritically uses an applicant's objectives as the benchmark for evaluation, and fails to include its own statement of purpose and objectives. A range of alternatives that is based exclusively on "the applicant's project objectives," and not incorporating any public purpose, need, or objectives that have been adopted by the lead agency, thus cannot comply with CEQA. Moreover, reliance exclusively on applicant project objectives is particularly inappropriate where there are unmitigable significant impacts that will require the County to find overriding considerations, given the need for the objectives to "aid the decision makers in preparing findings or a statement of overriding considerations, if necessary."[87]

Third, without a proper analysis of the Project's impacts, any alternatives analysis is necessarily flawed because the comparison of Project impacts to the anticipated impacts of alternatives will be unsupported by substantial evidence. Here, the significant deficiencies in the Recirculated Draft EIR's analysis of Project impacts make any comparison of those impacts with the impacts of proposed alternatives meaningless.

This deficiency in the Recirculated Draft EIR—flawed impact analysis leading to flawed alternatives analysis—is apparent across multiple impact areas, discussed throughout these comments. Any comparison of the impacts of the Project with the impacts of alternatives will fail if the Project impacts are misstated or improperly analyzed. But the deficiency is most glaring in the context of GHG impacts, where the Recirculated Draft EIR's alternatives analysis asks its readers to accept a paradox: first, the Project will have significant unmitigable impacts on GHG emissions.[88] Second, the no-project alternative will have less-than-significant impacts on GHG emissions.[89] And third, at the same time, according to the Recirculated Draft EIR, the no-project

[85] RDEIR, Vol. 1 at 3-7, 6-7 to 6-8.
[86] *North Coast Rivers Alliance*, *supra,* 243 Cal.App.4th at 666 (citing Pub. Resources Code, §21001(g) (internal quotation omitted)); see also CEQA Guidelines, §15124(b).
[87] CEQA Guidelines, § 15124(b); see *Preservation Action v. San Jose* (2006) 141 Cal.App.4th 1336, 1351–52 ("Since CEQA charges the agency, not the applicant, with the task of determining whether alternatives are feasible, the circumstances that led the applicant in the planning stage to select the project for which approval is sought and to reject alternatives cannot be determinative of their feasibility. The lead agency must *independently* participate, review, analyze and discuss the alternatives in good faith." [citing *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 736]).
[88] RDEIR, Vol. 1 at 4.8-28 ("Level of Significance After Mitigation: [GHG] Impacts would be significant and unavoidable."), 4.8-31 (same), 6-5 to 6-6 ("the project would conflict with any applicable plan, policy, or regulation adopted for the purpose of reducing emissions of GHG, thus causing a significant and unavoidable impact, even with mitigation. Finally, the project would make a cumulatively considerable contribution to a cumulative GHG emissions impact, even with mitigation, and this impact is therefore significant and unavoidable"), 6-22 (Project GHG impacts "significant and unavoidable").
[89] RDEIR, Vol. 1 at 6-14 ("Impacts would be less than significant under this alternative [Alternative 1, the "no project" alternative]").

alternative's impacts are "greater than project" impacts.[90] On its face, this analysis cannot stand scrutiny, since it is internally inconsistent. This internal inconsistency, in turn, is a consequence of a fundamental failure in the underlying Project GHG analysis and conclusions, as discussed below.

These analytical failures render the Recirculated Draft EIR's alternatives analysis deficient. And beyond that, the failures also constitute fundamental informational deficiencies in the document. It is not possible for the public or a decisionmaker to compare the alternatives meaningfully if the conclusions being compared are incoherent or internally inconsistent, as is the case here.

B. The Recirculated Draft EIR Fails to Adequately Consider a Reasonable Range of Alternatives.

An EIR must consider a reasonable range of alternatives which "offer substantial environmental advantages over the project proposal."[91] The Public Resources Code makes it clear that proper alternatives need to "substantially lessen" the significant environmental effects of a project.[92] Here, the Recirculated Draft EIR rejects without analysis several alternatives that meet that criterion and satisfy at least some project objectives. This improper failure to consider alternatives appears to have occurred, at least in part, because the applicant's project objectives are drawn too narrowly,[93] and the applicant's conception of "feasibility" is improperly constrained.[94]

The lead agency, not the applicant, bears the responsibility to evaluate alternatives based on project objectives, as demonstrated above.[95] "[A]n agency may not approve a proposed project if feasible alternatives exist that would substantially lessen its significant environmental effects."[96] The lead agency also must evaluate feasibility based on objective criteria. "Feasible" means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."[97]

Here, the Recirculated Draft EIR should have considered a wider range of alternatives that minimize or avoid impacts from the proposed Project. Alternatives that involve eliminating or reducing oil extraction from CRC's oil fields, for example, satisfy most of even the applicant's project objectives, including contributing to CRC's adopted goals of Full-Scope Net

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[90] RDEIR, Vol. 1 at 6-22 (no-project alternative's GHG impacts identified as "Greater Than Project"), 6-24 ("Alternative 1, the No Project Alternative[,] would be environmentally superior to the project on the basis of the minimization or avoidance of physical environmental impacts but *would have greater impacts than the project for GHG emissions*" [emphasis added]).

[91] *Citizens of Goleta Valley*, *supra*, 52 Cal.3d at 566.

[92] Pub. Resources Code, § 21002; see also CEQA Guidelines, § 15126.6(a).

[93] *North Coast Rivers Alliance*, *supra*, 243 Cal.App.4th at 668.

[94] *Preservation Action*, *supra*, 141 Cal.App.4th at 1351–52.

[95] *Kings County Farm Bureau*, *supra*, 221 Cal.App.3d at 736; *Preservation Action*, *supra*, 141 Cal.App.4th at 1351–52.

[96] CEQA Guidelines, § 21081; *Mountain Lion Foundation v. Fish Game Com.* (1997) 16 Cal.4th 105, 134.

[97] Pub. Resources Code, § 21061.1; *Cal. Native Plant Society*, *supra*, 177 Cal.App.4th at 960.

Zero emissions by 2045, supporting California's Executive Order B-55-18, and siting and designing the Project in an environmentally responsible manner. If the goal is to keep oil field-generated CO_2 out of the atmosphere, there are alternative ways to accomplish this that the Recirculated Draft EIR fails to consider.

The Recirculated Draft EIR should be revised to consider these and other reasonable alternatives, as required under CEQA.

C. The Recirculated Draft EIR's Discussion of Alternative 1, the "No Project" Alternative, is Inadequate Under CEQA.

The Recirculated Draft EIR's "no project" alternative discussion provides a brief examination, unsupported by evidence or analysis, of the environmental consequences of not permitting the Project or any alternative. This summary discussion of Alternative 1 is inadequate under CEQA because it fails to include basic information about the no-project alternative.

The CEQA Guidelines require that the no project analysis discuss "what would be reasonably expected to occur in the foreseeable future if the project were not approved, based on current plans and consistent with available infrastructure and community services."[98] Here, however, the discussion lacks "adequate information regarding the no-project alternative" that would allow the decisionmakers to make "an informed, reasoned decision on whether this Project should go forward."[99] In *Save the Hill Group v. City of Livermore*, the court found that a "no-project" alternative that failed to provide adequate information as to what would be reasonably expected to occur if a project would not go forward was in violation of CEQA, and set the EIR approval aside.[100]

The same reasoning applies here. The Recirculated Draft EIR should contrast the impacts of the proposed Project with the impacts of the no-project alternative, with specificity and, where possible, quantification, across all impact categories. It should provide a "factually based forecast of the environmental impacts of preserving the status quo."[101] Instead, the Recirculated Draft EIR includes a cursory narrative discussion, with no supporting evidence or analysis, articulating only what the applicant asserts the consequences of the no-project alternative would be. The Recirculated Draft EIR then bases its comparison with the proposed Project on this thin, non-evidence-based discussion.

This missing information is, in the words of the *Save the Hill Group* court, "just the sort of information CEQA intended to provide those charged with making important, often irreversible, environmental choices on the public's behalf."[102] The alternatives analysis must be revised to provide a robust discussion of the "no-project" reasonable consequences.

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[98] CEQA Guidelines, § 15126.6(e)(2).
[99] *Save the Hill Grp. v. City of Livermore* (2022) 76 Cal.App.5th 1092, 1113, review denied (July 13, 2022).
[100] *Id.* at 1113.
[101] *Ctr. for Biological Diversity v. Dept. of Fish & Wildlife* (2015) 234 Cal.App.4th 214, 253.
[102] *Save the Hill Grp.*, *supra*, 76 Cal.App.5th at 1113.

Additionally, as discussed above, the analysis of the no-project alternative is inadequate because the comparison between the no-project alternative and the proposed Project is misleading, inconsistent, and incoherent. The Recirculated Draft EIR's characterization of Alternative 1 as having greater GHG impacts than the Project, in particular, reflects a failure to adequately and coherently describe and analyze this alternative as well as a failure to coherently analyze the Project's impacts.[103]

Finally, an adequate analysis of Alternative 1 would also address the failures, highlighted elsewhere in these comments, in framing project objectives and in neglecting to analyze the fact that the Project is designed to facilitate and justify the continued extraction of oil and burning of fossil fuels for energy. An adequate comparative analysis between the impacts of Alternative 1 and the Project would require analysis of the Project's sources of CO_2 and of the Project's facilitation of fossil fuel extraction and combustion.

D. The Recirculated Draft EIR Fails to Adequately Describe or Analyze Alternatives 2 and 3.

The Recirculated Draft EIR's discussion of the two "action" alternatives, DAC (Alternative 2) and nature-based carbon storage (Alternative 3), is cursory and lacking in specificity, evidence, and support.[104] The Recirculated Draft EIR not only fails to describe either alternative with specificity, but also fails to disclose or even meaningfully attempt to discuss the projected impacts of either alternative. As a consequence, the document fails to support its conclusions—where it compares alternatives' impacts with the Project's impacts—with substantial evidence.

First, Alternative 2, the DAC Alternative, fails to specify any of the major features of the hypothetical DAC facility that forms the basis of the alternative. The Recirculated Draft EIR does not even attempt to explain, for example, what technology would be used, the size and throughput of the facility, what infrastructure would be built and where, or what resources it would take to build and maintain that infrastructure and operate the facility. Instead, the document presents only a discussion of the generalized features of DAC technology and facilities, with not one word about how those features might or might not appear in the application of DAC as an alternative to the proposed Project, as discussed earlier in these comments.[105] The Recirculated Draft EIR then fails even to make a serious attempt to assess the

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[103] Compare RDEIR, Vol. 1 at 4.8-28 ("Level of Significance After Mitigation: [GHG] Impacts would be significant and unavoidable."), 4.8-31 (same), 6-5 ("the project would conflict with any applicable plan, policy, or regulation adopted for the purpose of reducing emissions of GHG, thus causing a significant and unavoidable impact, even with mitigation. Finally, the project would make a cumulatively considerable contribution to a cumulative GHG emissions impact, even with mitigation, and this impact is therefore significant and unavoidable"); 6-22 (Project GHG impacts "significant and unavoidable"), 6-14 ("Impacts would be less than significant under this alternative [Alternative 1, the "no project" alternative]") with Draft EIR, Vol. 1 at 6-22 (no-project alternative's GHG impacts identified as "Greater Than Project"), 6-24 ("Alternative 1, the No Project Alternative[,] would be environmentally superior to the project on the basis of the minimization or avoidance of physical environmental impacts but *would have greater impacts than the project for GHG emissions*" [emphasis added]).

[104] RDEIR, Vol. 1 at 6-17 to 6-21 (containing the Draft EIR's entire discussion of these two alternatives).

[105] RDEIR, Vol. 1 at 6-17 to 6-20 (containing the Draft EIR's discussion of Alternative 2, in full).

impacts of the DAC alternative in each impact category[106]—a task that would have been fruitless, given the lack of specificity about the alternative's basic features. Correspondingly, the Recirculated Draft EIR and appendices do not contain evidence, methodology, modeling, or calculations regarding any such impacts. And following from this, there is no substantial evidence—indeed, no evidence at all—supporting the Recirculated Draft EIR's comparison of Project impacts with the purely speculative conclusions about the DAC alternative's impacts. Nor is the brief discussion of whether Alternative 2 meets project objectives[107] supported by substantial evidence, for the same reasons—and additionally because, as explained above, the project objectives themselves are fatally flawed. The lead agency is required to meaningfully develop and analyze this alternative, and has failed entirely to do that.

Second, Alternative 3, the "Nature Based Carbon Storage" alternative, also fails to meaningfully specify any of the features of the alternative. While the Recirculated Draft EIR sets forth some general ideas about what types of features this potential alternative might include, the alternative remains completely unformed and unanalyzed.[108]

This text, with the "example" of "planting of trees," comes closest to articulating the features of Alternative 3:

> The most applicable nature-based carbon storage alternative for the area of the project site would be regenerative agriculture, as it coincides with the current zoning. Planting of trees would be one example of regenerative nature-based carbon storage for the highest ability to store atmospheric carbon.[109]

It is clear on its face that this statement does not present a specific alternative to the proposed Project. As with Alternative 2, the Recirculated Draft EIR lacks any discussion, beyond the speculation above, of what technology will be used, much less how the alternative would be configured, or what, specifically, it would entail.[110] And the closest the Recirculated Draft EIR comes to articulating the scope or size of this alternative is in a purely conditional, hypothetical statement: "If 9,000 acres of the project site were remediated of all oil and gas facilities and prepared for planting, an estimated 400 to 1,000 trees per acre could be planted, resulting in a new forest area of 3.6 million to 9 million trees."[111] Notably, even all these hypothetical statements in the Recirculated Draft EIR lack any evidence or foundation in the document or appendices, but instead just appear as assertions, without any references or citations to articulate or support any methodology, analysis, or conclusions.

Accordingly, there is no meaningful analysis of either the features or impacts of the alternative, making it impossible to compare the Project's impacts with the alternative's impacts, and making the conclusions in that attempted comparison lacking in substantial evidence for support. Nor is the brief discussion of whether Alternative 3 meets project objectives[112]

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[106] *Id.*
[107] *Id.*
[108] RDEIR, Vol. 1 at 6-20 to 6-21 (containing discussion of Alternative 3, in full).
[109] RDEIR, Vol. 1 at 6-20.
[110] RDEIR, Vol. 1 at 6-19 to 6-21.
[111] RDEIR, Vol. 1 at 6-20.
[112] RDEIR, Vol. 1 at 6-21.

supported by substantial evidence, for the same reasons—and additionally because, as explained above, the project objectives themselves are fatally flawed.

V. THE RECIRCULATED DRAFT EIR FAILS TO ANALYZE AND MITIGATE SIGNIFICANT IMPACTS

The discussion of a proposed project's environmental impacts is an essential component of an EIR.[113] The fundamental purpose of CEQA is to "inform the public and its responsible officials of the environmental consequences of their decisions *before* they are made."[114] To do so, an EIR must contain facts *and* analysis, not just an agency's bare conclusions.[115]

As explained in detail below, the Recirculated Draft EIR's environmental impacts analysis is deficient under CEQA because it fails to provide the necessary facts and analysis to allow the County and the public to make informed decisions about the CTV I Project.

CEQA also requires an EIR to describe and adopt all feasible mitigation measures to address a project's significant environmental impacts.[116] Mitigation measures must be "fully enforceable through permit conditions, agreements, or other legally binding instruments."[117]

Generally, the "[f]ormulation of mitigation measures should not be deferred until some future time."[118] As an exception, "measures may specify performance standards which would mitigate the significant effect of the project and which may be accomplished in more than one specified way."[119] Crucially, there is a "distinction between stating a generalized goal and adopting specific performance criteria," and "[s]imply stating a generalized goal for mitigating an impact does not allow the measure to qualify for the exception to the general rule against the deferred formulation of mitigation measures."[120] Further, even where the deferred formulation of mitigation might be allowable, there is a point beyond which delayed implementation is not allowed: "[o]nce the project reaches the point where activity will have a significant adverse effect on the environment, the mitigation measures must be in place."[121]

"Where several measures are available to mitigate an impact, each should be discussed and the basis for selecting a particular measure should be identified."[122]

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[113] See CEQA Guidelines, § 15126.2(a) ("An EIR *shall* identify and focus on the significant effects of the proposed project on the environment.") (emphasis added).
[114] *Laurel Heights Improvement Assn. v. Regents of Univ. of Cal.*, 6 Cal.4th 1112, 1123.
[115] *Citizens of Goleta Valley*, *supra*, 52 Cal.3d at 568.
[116] Pub. Resources Code, § 21002; CEQA Guidelines, § 15126.4(a)(1).
[117] CEQA Guidelines, § 15126.4(a)(1)(B), (a)(2).
[118] CEQA Guidelines, § 15126.4(a)(1)(B).
[119] *King & Gardiner Farms, LLC v. County of Kern* (2020) 45 Cal.App.5th 814, 856.
[120] *Id.* at 856.
[121] *Id.* at 860, quoting *POET, LLC v. Cal. Air Resources Bd.* (2013) 218 Cal.App.4th 681, 738.
[122] CEQA Guidelines, § 15126.4(a)(1)(B).

As discussed below, throughout the Recirculated Draft EIR, the County's proffered mitigation measures are insufficient, riddled with inconsistencies, and ultimately not adequate to satisfy CEQA's legal requirements.

A. The Recirculated Draft EIR's Analysis and Mitigation of Air Quality Impacts is Inadequate.

1. The Recirculated Draft EIR states heavy-duty truck traffic is expected for Project operations but does not describe or analyze the impacts of such traffic.

Within the chapter on project description, in the section for "Operational and Maintenance Activities," the Recirculated Draft EIR describes five full-time employees who will be onsite at all times and another five employes who may need to be onsite when repairs or other maintenance is required.[123] The Recirculated Draft EIR calculates "Operational Traffic" for these employees, who are expected to collectively make 20 daily trips in "Passenger Vehicles."[124]

Separately, the discussion of "Operational Traffic" includes a heading for "Truck Traffic," which is followed by one sentence that states: "It is anticipated that diesel heavy heavy-duty trucks would make 40 trips per day following the access routes designated for travel."[125] No further information on the nature, purpose, or impacts of this operational heavy-duty truck traffic is provided in the project description chapter. Nor is there any further discussion anywhere else in the Recirculated Draft EIR.

As noted above, the Recirculated Draft EIR must be revised to thoroughly explain this aspect of the CTV I Project. Based on the County's previous statement in the Notice of Preparation/Initial Study that "[t]he proposed project would take local industrial sources of CO_2 that are transported by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells for the project,"[126] it seems likely these trucks will be carrying CO_2 from offsite industrial sources

In addition to fully explaining the nature and purpose of the operational heavy-duty truck trips in the project description, the impacts of such heavy-duty truck traffic during Project operation must be analyzed and mitigated consistent with CEQA's requirements. As acknowledged in the Notice of Preparation/Initial Study, truck and other vehicle traffic threatens significant direct and cumulative impacts in at least the following categories: air quality, energy demand and consumption, greenhouse gas emissions, hazards and hazardous materials, noise, and transportation and traffic.[127] Depending on the nature and purpose of the operational heavy-duty truck traffic, additional significant impacts are possible.

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[123] RDEIR, Vol. 1 at 3-38.
[124] RDEIR, Vol. 1 at 3-35 to 3-38.
[125] RDEIR, Vol. 1 at 3-38.
[126] *Notice of Preparation/Initial Study* at 4.
[127] *Notice of Preparation/Initial Study* at 24–25, 29, 32, 34–35, 40, 44–45.

2. The Recirculated Draft EIR must be updated to address the revised national ambient air quality standard for $PM_{2.5}$.

The Air Quality section of the Recirculated Draft EIR must be updated to reflect the U.S. EPA's issuance of a new national ambient air quality standard (NAAQS) for fine particulate matter, also known as $PM_{2.5}$. On February 7, 2024, U.S. EPA strengthened the annual health-based NAAQS for $PM_{2.5}$ from a level of 12 micrograms per cubic meter to 9 micrograms per cubic meter.[128]

Beyond just acknowledging the new standard, the Recirculated Draft EIR should also address the implications of the new annual $PM_{2.5}$ NAAQS: air quality in Kern County currently does not meet the new standard[129] and is not expected to meet it in 2032,[130] meaning the San Joaquin Valley Air Pollution Control District (Air District) will have to institute further restrictions on polluting projects and activities through the San Joaquin Valley airshed, including in Kern County.[131]

3. The Recirculated Draft EIR must be updated to make clear the full danger posed by increased $PM_{2.5}$ emissions.

a. The Recirculated Draft EIR should disclose that there is no safe level of exposure to $PM_{2.5}$.

Along with U.S. EPA's issuance of its revised $PM_{2.5}$ NAAQS, the agency also summarized the latest scientific studies on the health effects of $PM_{2.5}$.

The Recirculated Draft EIR should update its discussion of the health effects of $PM_{2.5}$ to reflect the latest science summarized by U.S. EPA in its standard-setting decision. Such an

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[128] See generally EPA, *Reconsideration of the National Ambient Air Quality Standards for Particulate Matter*, 89 Fed. Reg. 16202 (Mar. 6, 2024), https://www.federalregister.gov/documents/2024/03/06/2024-02637/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter; accord, EPA, *EPA Finalizes Stronger Standards for Harmful Soot Pollution, Significantly Increasing Health and Clean Air Protections for Families, Workers, and Communities* (Feb. 7, 2024), https://www.epa.gov/newsreleases/epa-finalizes-stronger-standards-harmful-soot-pollution-significantly-increasing.

[129] See EPA, *EPA Finalizes Stronger Standards for Harmful Soot Pollution, Significantly Increasing Health and Clean Air Protections for Families, Workers, and Communities* at Figure 1; accord EPA, *Fine Particle Concentrations for Counties with Monitors Based on Air Quality Data from 2020 – 2022* at 1, https://www.epa.gov/system/files/documents/2024-02/table_annual-pm25-county-design-values-2020-2022-for-web.pdf (last accessed Mar. 1, 2024).

[130] EPA, *EPA Projects More than 99% of Counties Would Meet the Revised Fine Particle Pollution Standard* (Feb. 7, 2024), https://www.epa.gov/system/files/documents/2024-02/2024-pm-naaqs-final-2032-projections-map.pdf.

[131] Lazo, *California's Pursuit of Clean Air Just Got Much Harder: New Soot Standards Set*, Cal Matters (Feb. 7, 2024) ("Achieving the new target will take wide-ranging new state and local regulations aimed at cutting emissions"), https://calmatters.org/environment/2024/02/california-new-soot-standards.

update is necessary because CEQA requires that an EIR conduct "an analysis that connect[s] the air quality effects to human health consequences."[132]

Of key importance to disclose to Kern County residents and decisionmakers: currently available evidence indicates there is no safe level of exposure to $PM_{2.5}$.[133] Consequently, it is essential that the County adopt all feasible mitigation for increased $PM_{2.5}$ emissions.

b. The Recirculated Draft EIR should better address the relationship between $PM_{2.5}$ and DPM.

The Recirculated Draft EIR's description of air pollutants and health effects discusses "Particulate Matter (PM_{10} and $PM_{2.5}$)" separately from "Diesel Particulate Matter."[134]

The discussion of $PM_{2.5}$ notes that "$PM_{2.5}$ constitutes a large portion of combustion particulates, including diesel particulate matter (DPM)," (p. 4.3-14) but does not direct the reader to the separate, further discussion of the dangers of DPM.

To prevent confusion and to convey the full extent of the health risks posed by $PM_{2.5}$, the Recirculated Draft EIR's discussion of $PM_{2.5}$ should include a cross reference to the more detailed discussion of DPM in the section that addresses "Health Effects and Risks of Toxic Air Contaminants."

Confusingly, the Recirculated Draft EIR's discussion of $PM_{2.5}$ currently includes an erroneous cross reference. At Volume 1, page 4.3-15, the text states: "The section below entitled 'Oil and Gas Operations and Health Effects' further discusses potential health effects of $PM_{2.5}$ emissions, among other things." But no such section with that title exists.

c. The Recirculated Draft EIR should address how $PM_{2.5}$ exacerbates illness and death from COVID-19.

The Recirculated Draft EIR's discussion of the health effects of $PM_{2.5}$ fails to adequately address "the nature and magnitude"[135] of the CTV I Project's increased emissions because it does not acknowledge the studies that demonstrate that exposure to $PM_{2.5}$ has been found to lead to an increase in the death rate for COVID-19, especially for people of color.[136] Indeed, one

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[132] *Sierra Club v. County of Fresno* (2018) 6 Cal.5th 502, 522.
[133] According to EPA: "[t]he currently available evidence does not identify particular PM2.5 concentrations that do not elicit health effects. Rather, health effects can occur over the entire distribution of ambient PM2.5 concentrations evaluated, and epidemiologic studies conducted to date do not identify a population-level threshold below which it can be concluded with confidence that PM2.5-related effects do not occur." 89 Fed. Reg. 16249.
[134] Compare RDEIR, Vol. 1 at 4.3-13 to 4.3-15 with *id.* at 4.3-25 to 4.3-26.
[135] *Sierra Club*, *supra*, 6 Cal.5th at 522.
[136] See Cal. Dept. of Public Health, *State Officials Announce Latest COVID-19 Facts* (News Release No. NR20-111) (June 3, 2020), https://www.cdph.ca.gov/Programs/OPA/Pages/NR20-111.aspx;

recent study determined that thousands of COVID-19 deaths could have been prevented during the first year of the COVID-19 pandemic in California, especially in the San Joaquin Valley, if ambient levels of $PM_{2.5}$ pollution were lower.[137]

The Recirculated Draft EIR therefore should be updated with a discussion of the health risks posed by COVID-19 generally, along with a further discussion of the COVID-19 morbidity and mortality increased by exposure to $PM_{2.5}$.

Notably, the Recirculated Draft EIR includes a proposed mitigation measure (MM 4.3-7) that addresses COVID-19, stating that: "Owner/operators shall implement all orders related to the COVID-19 pandemic or any other pandemic mandated by Kern County Public Health on well sites and related to worker safety."[138] To provide context for this mitigation measure, the Recirculated Draft EIR should be revised as recommended above to make clear why COVID-19 is a health concern, particularly for a project that is expected to significantly increase $PM_{2.5}$ emissions.

4. The Recirculated Draft EIR contradicts earlier statements about the nearest sensitive receptor.

The Recirculated Draft EIR states: "The closest sensitive receptor to the project site is McKittrick Elementary School, which is 4.47 miles southwest of the facility pipeline and injection well 357-7R. The nearest residence is approximately 4.4 miles southeast of the injection line and 4.4 miles from injection well 345-36R."[139] In contrast, the Initial Study/Notice of Preparation states: "The sensitive receptor closest to the project site is the rural residence approximately 1 mile to the south of the project site."[140]

It is important for purposes of both impact analysis and mitigation that the Recirculated Draft EIR correctly identifies the nearest sensitive receptor. The County must explain the

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Chow, D.S. et al., *The Disproportionate Rise in COVID-19 Cases Among Hispanic/Latinx in Disadvantaged Communities of Orange County, California: A Socioeconomic Case-Series*, Johns Hopkins Bloomberg School of Public Health (2020), https://www.medrxiv.org/content/10.1101/2020.05.04.20090878v1.full.pdf; Goyal, M.K. et al., *Racial/Ethnic and Socioeconomic Disparities of SARS-CoV-2 Infection Among Children*, Pediatrics (2020), https://pediatrics.aappublications.org/content/pediatrics/early/2020/08/03/peds.2020-009951.full.pdf; Petroni, M., et al., *Hazardous Air Pollutant Exposure As a Contributing Factor to COVID-19 Mortality in the United States*, Environ. Res. Lett., Vol. 15, no. 9 (Sept. 11, 2020), https://iopscience.iop.org/article/10.1088/1748-9326/abaf86; Tian, H. et al., *Risk of COVID-19 is Associated with Long-term Exposure to Air Pollution*, medRxiv (Apr. 24, 2020), https://doi.org/10.1101/2020.04.21.20073700; Wu, X. et al., *Exposure to Air Pollution and COVID-19 Mortality in the United States: A Nationwide Cross-Sectional Study* (updated Nov. 4, 2020), https://projects.iq.harvard.edu/covid-pm/home; Zhu, Y., *Association Between Short-Term Exposure to Air Pollution and COVID-19 Infection: Evidence from China*, 727 Science of the Total Environment (Apr. 2020), https://doi.org/10.1016/j.scitotenv.2020.138704.

[137] English, P.B. et al., *Association Between Long-Term Exposure to Particulate Air Pollution with SARS-CoV-2 Infections and COVID-19 Deaths in California, U.S.A.*, Environmental Advances 9 (2022) 100270, https://doi.org/10.1016/j.envadv.2022.100270.

[138] RDEIR, Vol. 1 at 1-31, 4.3-74.

[139] RDEIR, Vol. 1 at 1-5.

[140] *Notice of Preparation/Initial Study* at 3.

discrepancy between the Recirculated Draft EIR and the Initial Study/Notice of Preparation and, if the nearest sensitive receptor is actually only one mile away, revise its impacts analysis and mitigation measures accordingly.

5. The Recirculated Draft EIR's air quality impact analysis is premised on unexplained and/or faulty assumptions.

As set forth in the attached Sahu Report, the Recirculated Draft EIR's assessment of impacts and formulation of mitigation measures is inadequate because it is premised on assumptions that are unexplained if not faulty.[141] For example:

- The data provided on "Existing Air Quality" is dated—covering 2019 to 2021—and therefore may not be representative of current air quality in Kern County.
- Nowhere does the Recirculated Draft EIR or accompanying report prepared by Trinity Consultants explain the assumptions upon which the emissions estimates are made. It is unclear how the various emissions factors were selected and whether they are representative of expected activities and equipment for the CTV I Project.
- Further, assumptions about the expected project activities are unexplained despite their uncanny precision (e.g., well pad construction is expected to take 11 days; every well to be drilled is identified with a specific and unique depth; five hydrocranes are expected to operate exactly 1968.75 hours).
- The Recirculated Draft EIR suggests false precision by failing to disclose quantitative error ranges and/or to qualitatively explain the uncertainty inherent in the emission estimates.
- Additionally, page 4-6 of the Trinity Consultants' report is completely blank. It is unclear whether this was intentional, or perhaps a formatting issue. To the extent information is missing—it should be provided to the public with appropriate time for review.

6. The Recirculated Draft EIR fails to adequately address cumulative air quality impacts.

The Recirculated Draft EIR acknowledges that the CTV I Project will contribute to cumulatively significant air quality impacts. It states: "Because the project's specific emissions would contribute to Kern County's 2020 emissions inventory and to the 2025 projected

[141] Dr. Sahu's report addresses the original Draft EIR, but his assessment of the County's flawed air quality emissions estimates and inadequate mitigation measures applies fully to the Recirculated Draft EIR. The text of Section 4.3 ("Air Quality") of the Recirculated Draft EIR is nearly word-for-word identical to the original Draft EIR, with no substantive changes made to the County's analysis, emissions estimates, or mitigation measures. Compare, e.g., RDEIR, Vol. 1 at 4.3-60 to 4.3-81 with DEIR, Vol. 1 at 4.3-60 to 4.3-81. Further, Section 4.3 of the Recirculated Draft EIR continues to rely on the same "AIR QUALITY IMPACT ANALYSIS" prepared by Trinity Consultants, dated May 2023 and revised November 2023.

emissions of Kern County, *the project's incremental effects on air quality would be cumulatively considerable* and, even with mitigation, this potentially significant cumulative impact would be cumulatively significant and unavoidable."[142]

Although the Recirculated Draft EIR acknowledges a significant cumulative impact on air quality, it does not evaluate or explain the severity of the impact or its consequences for local residents. The Recirculated Draft EIR's bare conclusion—without further analysis—violates CEQA because "a sufficient discussion of significant impacts requires not merely a determination of whether an impact is significant, but some effort to explain the nature and magnitude of the impact."[143] Further, the Recirculated Draft EIR is inadequate because, for an analysis of air quality impacts, an EIR must explain the "connection . . . between the two segments of information presented in the EIR—potential project emissions and human health impacts."[144]

To adequately address the CTV I Project's cumulative air quality impacts, the Recirculated Draft EIR should address "how the environmental and public health burdens of a project might specially affect certain communities."[145] As part of this analysis, the document should account for increased emissions from the Project "together with any pollution burdens [nearby] communities already are bearing, or may bear from probable future projects."[146]

A thorough analysis of cumulative air quality impacts is crucial because Kern County already experiences some of the worst and unhealthiest air quality in the country.[147] Not only will the Project itself generate increased air pollution, but it will incentivize the development of other dirty industrial sources that necessarily will be concentrated nearby and will contribute to worse overall air quality owing to the Project's requirement that it will only accept CO_2 from local sources in Kern County.[148]

Such poor air quality is particularly burdensome because "Kern County has a higher percentage of Hispanic, linguistically isolated, and pollution burdened populations than do other areas of California."[149] Indeed the majority-Hispanic residents (63.9 percent) nearest to the proposed CTV I Project are particularly overburdened already: the Project has been proposed for a census tract that already faces one of the highest pollution burdens in the state (96th percentile)

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[142] RDEIR, Vol. 1 at 1-12, 5-3 (emphasis added).
[143] *Sierra Club*, *supra*, 6 Cal.5th at 519.
[144] *Id.* at 520.
[145] Office of the Cal. Attorney General, *Environmental Justice at the Local and Regional Level* (2012) at 3, https://oag.ca.gov/sites/all/files/agweb/pdfs/environment/ej_fact_sheet.pdf.
[146] *Id.* at 4.
[147] American Lung Assn., *State of the Air* (2024) at 15–21 (listing Bakersfield, CA as the most polluted city in U.S. for daily and annual particulate matter and the third-most polluted city for ozone), https://www.lung.org/getmedia/dabac59e-963b-4e9b-bf0f-73615b07bfd8/State-of-the-Air-2024.
[148] RDEIR, Vol. 1 at 4.11-53 to 4.11-54 (stating in MM 4.11-7 that "Source[s] of CO_2 must be from an industry within Kern County").
[149] Kern County Planning & Natural Resources Dept., *Final Supplemental Recirculated Environmental Impact Report (October 2020) for Revisions to Title 19-Kern County Zoning Ordinance–(2020 A), Focused on Oil and Gas Local Permitting* (Jan. 2021), section 7.2.6 (Response to Comments of Interested Parties), response to comment 0010-3.

as well as challenges posed by unemployment (89th percentile), poverty (86th percentile), and linguistic isolation (83rd percentile).[150]

Notably, in addition to thoroughly addressing the existing air pollution burden in the Project area, the Recirculated Draft EIR must also address "probable future projects."[151] As discussed elsewhere in these comments, the CTV I Project represents merely one component of extensive further industrial development that is expected in the area.

In addition to adequately analyzing cumulative effects of the CTV I Project in the context of the existing pollution burden on frontline communities and expected future projects, the County must then reassess the Recirculated Draft EIR's evaluation of alternatives and identification of all feasible mitigation measures. As explained by the Office of the Attorney General, "[w]here a local agency has determined that a project may cause significant impacts to a particular community or sensitive subgroup, the alternative and mitigation analyses should address ways to reduce or eliminate the project's impacts to that community or subgroup."[152] Pursuant to CEQA's requirements and consistent with the Office of the Attorney General's guidance, the County should work with the public and affected communities to develop mitigation measures that will adequately address the CTV I Project's cumulative impacts.

7. The Recirculated Draft EIR fails to adopt all feasible mitigation to control fugitive dust.

The Recirculated Draft EIR acknowledges that PM_{10} is largely emitted as fugitive dust, often generated by construction, demolition, excavation, extraction, and/or other earthmoving activities.[153] Such activities—as well as vehicle traffic, another source of PM_{10}—will occur at the CTV I Project site, and the Recirculated Draft EIR concludes that the Project's construction and operational activities will cause a significant increase in PM_{10} emissions.[154] Consequently, all feasible mitigation for PM_{10} must be adopted.

Mitigation Measure (MM) 4.3-2 specifies that "The Owner/operator shall develop and implement a Fugitive Dust Control Plan in compliance with San Joaquin Valley Air Pollution Control District fugitive dust suppression regulations."[155] The Measure further specifies 14 specific "dust control measures [that] shall be implemented."[156]

The prescribed specific measures set forth in MM 4.3-2 are inadequate and do not represent all feasible mitigation for fugitive dust at the Project site. Inexplicably, MM 4.3-2 does not include all feasible measures identified by the San Joaquin Valley Air Pollution Control

[150] Office of Environmental Health Hazard Assessment (OEHHA), *CalEnviroScreen 4.0*, results for 6029003700, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Feb. 26, 2024).
[151] Office of the Cal. Attorney General, *Environmental Justice at the Local and Regional Level* at 4.
[152] *Id.* at 4.
[153] RDEIR, Vol. 1 at 4.3-14, 4.3-38 to 4.3-39.
[154] RDEIR, Vol. 1 at 4.3-63 to 4.3-68.
[155] RDEIR, Vol. 1 at 4.3-58.
[156] RDEIR, Vol. 1 at 4.3-58 to 4.3-59.

District in its most recent Guidance for Assessing and Mitigating Air Quality Impacts.[157] Nor does MM 4.3-2 institute all measures contemplated by the Air District's Regulation VIII.[158] Indeed, some of the measures set forth in MM 4.3-2 contradict stricter requirements set forth in Regulation VIII.

Consistent with CEQA's requirement to adopt all feasible mitigation, MM 4.3-2 should be revised to reflect stronger and/or additional mitigation to control fugitive dust.

MM 4.3-2 must be strengthened not only to comply with CEQA, but to abide by the legislative directive that CCUS projects like CTV I "include . . . [s]trategies to minimize, to the maximum extent technologically feasible, copollutant emissions from facilities where CCUS or CDR technology is deployed to ensure that the use of carbon dioxide removal technologies and carbon capture and storage technologies does not have an adverse impact on local air quality and public health, particularly in low-income and disadvantaged communities."[159]

Consequently, MM 4.3-2 should be revised to include the following:

- Work should be phased to reduce the amount of disturbed surface area at any one time.[160] The Owner/operator should be required to describe how it intends to phase work in the required Fugitive Dust Control Plan.
- At all times, for all activities (i.e., *not* just excavated soil piles, construction activities on unpaved surfaces, and grading), visible dust emissions should be limited to 20% opacity.[161]
- Wind barriers should be constructed and maintained to limit visible dust emissions to 20% opacity.[162] The Owner/operator should be required to describe where and how it will construct and maintain wind barriers in the required Fugitive Dust Control Plan.
- Traffic speeds on unpaved roads should be limited to 15 miles per hour (*not* 25), with speed limit signs posted.[163]
- Construction activities should be discontinued whenever visible dust emissions exceed 20% opacity, even if ambient wind speeds do not exceed 25 miles per hour.[164]

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[157] See San Joaquin Valley Air Pollution Control District (SJVAPCD), *Guidance for Assessing and Mitigating Air Quality Impacts* (Mar. 19, 2015) at 77–78, https://www.valleyair.org/transportation/GAMAQI.pdf.
[158] The Air District's Regulation VIII and its constituent rules are described in the Recirculated Draft EIR in Volume 1 at 4.3-38 to 4.3-39. Further, it is available on the Air District's website at https://ww2.valleyair.org/rules-and-planning/current-district-rules-and-regulations/regulation-viii-fugitive-pm10-prohibitions/.
[159] Health & Safety Code, § 39741.1(a)(3)(A).
[160] Rule 8021, section 5.2 and table 8021-1.
[161] Rule 8021, sections 5.0, 5.2, 5.4.1, and table 8021-1; Rule 8051, section 5.0.
[162] Rule 8021, section 5.2 and Table 8021-1.
[163] Rule 8021, section 5.3.
[164] Rule 8021, section 5.4.1.

- Track out should be prevented by one of the following: a grizzly with rails, pipes or grates to dislodge debris off exiting vehicles; a layer of washed gravel at one inch or larger in diameter, three inches deep; extension of paved road at least 100 feet from publicly maintained road; or installation of a wheel washer.[165]
- All visible carryout and trackout on paved public roads or the paved shoulders of a paved public road should be removed at the end of each workday;[166] it is not sufficient to isolate carryout or trackout behind a locked gate.
- For empty haul trucks, the interior of the cargo compartment must be cleaned or covered before the empty truck leaves the site.[167]

Additionally, MM 4.3-2 must specify that no construction or grading permits shall be issued, and no activities expected to cause fugitive dust emissions may otherwise commence, unless and until the Air District approves a Fugitive Dust Control Plan for the CTV I Project. The County must specify such a limitation because "mitigation measures must be in place" when a "project reaches the point where activity will have a significant adverse effect on the environment."[168]

8. The Recirculated Draft EIR does not provide adequate mitigation to protect sensitive receptors.

a. MM 4.3-6 is inadequate and does not constitute all feasible mitigation.

To protect sensitive receptors, MM 4.3-6 states: "No Class VI or Class II well shall be located within 4000 feet of any sensitive receptor."[169] According to the Recirculated Draft EIR, this measure is intended to mitigate an "escape" of CO_2 "into the atmosphere," which "could result in health impacts to humans and wildlife."[170]

While MM 4.3-6 appropriately establishes a sizeable setback from the CTV I Project's injection wells, it is unclear if the setback distance provides adequate mitigation because the Recirculated Draft EIR does not explain how the distance of 4,000 feet was selected. The Recirculated Draft EIR must be updated to substantiate that MM 4.3-6's setback distance is adequate to protect sensitive receptors, reflecting an assessment of site-specific factors.

Notably, as described in the "Failure Investigation Report" for the CO_2 pipeline rupture that occurred not far from Satartia, Mississippi, emissions from the rupture affected community

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[165] See Rule 8041, sections 5.8 and 5.9; see also Kern County Planning & Natural Resources Dept., *Recirculated Draft Environmental Impact Report for 99 Houghton Industrial Park Project* (Oct. 2019) (hereinafter "99 Houghton Recirculated Draft EIR") at 4.3-43, https://psbweb.kerncounty.com/UtilityPages/Planning/EIRS/99_Houghton/DEIR/_99_Houghton_RDEIR_Vol%201.pdf.
[166] Rule 8041, section 5.1.
[167] Rule 8031, table 8031-1.
[168] *King & Gardiner Farms, supra,* 45 Cal.App.5th at 860, quoting *POET, supra,* 218 Cal.App.4th at 738.
[169] RDEIR, Vol. 1 at 1-31, 4.3-74.
[170] RDEIR, Vol. 1 at 4.3-73.

members located "approximately one mile" away.[171] As a consequence of the rupture and the significant leak of CO_2, 45 people were taken to the hospital and all 200 residents of Satartia had to be evacuated.[172] The threat posed by CO_2 emissions from an injection well—particularly in the event of a blowout—would seem to be equal if not greater than the threat posed by a pipeline rupture.

Beyond the need to substantiate MM 4.3-6's setback distance for injection wells, the stated rationale for the measure makes plain the measure's inadequacy. As the Recirculated Draft EIR aptly notes, the escape of CO_2 "via either well failure *or pipeline rupture* . . . could result in health impacts to humans and wildlife."[173] Indeed, the incident near Satartia demonstrates that it is not only injection wells that pose a threat to public health, but also pipelines and presumably any other equipment or structure that could leak significant quantities of CO_2. Consequently, MM 4.3-6 should be revised to require a protective setback from not only the injection wells, but also the Project's pipelines and any other structures or equipment containing or conveying CO_2.

b. MM 4.3-8 constitutes inadequate and unlawfully deferred mitigation.

As a further measure to address air quality impacts on sensitive receptors, MM 4.3-8 sets forth the following monitoring requirements:

> Prior to issuance of any construction or grading permits, the Owner/operator shall consult with the San Joaquin Valley Air Pollution Control District and develop a draft Air Monitoring program for fence line monitoring of all air constituents generated by the CCS project including but not limited to: criteria pollutants, CO_2, and H_2S. The plan shall be reviewed and approved by both the San Joaquin Valley Air District and the California Air Resources Board, with a draft copy to the EPA UIC Program and Kern County Planning and Natural Resources, and implemented before any construction on the CCS facilities can occur. The final approved plan shall be provided to the EPA UIC Program and Kern County Planning and Natural Resources.[174]

Given the CTV I Project's potential to expose nearby community members to substantial concentrations of air pollution, both criteria air pollutants and toxic air contaminants, the County can and should insist on a robust monitoring plan to detect elevated pollution levels.

Unfortunately, MM 4.3-8 does nothing more than generically require development and approval of a future plan. The mitigation measure fails to identify any performance standards to be used to develop the monitoring plan and, equally important, neglects to identify performance standards for the mitigation to be instituted when the monitoring identifies significant impacts.

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[171] RDEIR, Vol. 2, Failure Investigation Report – Denbury Gulf Coast Pipelines LLC (May 26, 2022) at 3.
[172] RDEIR, Vol. 2, Failure Investigation Report – Denbury Gulf Coast Pipelines LLC at 2.
[173] RDEIR, Vol. 1 at 4.3-73 (emphasis added).
[174] RDEIR, Vol. 1 at 1-31 to 1-32, 4.3-74.

This open-ended and therefore potentially meaningless promise of a mitigation measure to be developed sometime in the future violates CEQA's requirements for deferred mitigation.

In *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099, the court rejected—for lack of any performance standards—a mitigation measure that required monitoring private wells near a quarry and, if an impact was found, specified that the project must replace the lost water from existing wells on the proponent's property. Even though the respondent county in *Gray* had "committed itself to a specific mitigation goal—the replacement of water lost by neighboring landowners because of mine operations," the court concluded the goal was not a specific performance standard that complied with CEQA.[175]

MM 4.3-8 is even more deficient than the mitigation measure rejected in *Gray*, as the Recirculated Draft EIR does not identify any performance standards for the monitoring plan to be established beyond the pollutants to be addressed, let alone any performance standards for the mitigation to be implemented upon the identification of impacts. To meet CEQA's requirements, MM 4.3-8 should identify:

- Specific monitoring parameters (e.g., spacing of monitors, equipment sensitivity, frequency of monitoring) and/or performance standards to be used to select monitoring parameters;
- Requirements for reporting monitoring results to the County and responsible agencies and/or performance standards to be used to develop such reporting requirements;
- Requirements for reporting monitoring results to affected communities, regional community-based organizations, and to the public online and/or performance standards to be used to develop such meaningful public disclosure;
- Threshold level(s) and requirements for notification of nearby residents, other affected communities, and schools when a threshold is exceeded and/or performance standards to be used to develop such public notification requirements;
- Threshold levels of air pollution that, if detected at the fenceline, will trigger mitigation and/or performance standards to be used to select appropriate thresholds for mitigation;
- Mitigation measures to be implemented if monitoring thresholds are exceeded and/or performance standards to be used to select effective mitigation measures.

To adequately protect community members, monitoring parameters for the plan to be developed pursuant to MM 4.3-8 should be developed with input from nearby residents and affected communities. Community input is particularly valuable and important for determining the locations of monitors (including, but not limited to, near sensitive receptors and along the

[175] *Gray, supra,* 167 Cal.App.4th at 1119.

project fenceline), the number of monitors, and the thresholds that will trigger community notification and response requirements.

9. The Recirculated Draft EIR fails to adopt all feasible mitigation to address Valley Fever.

The Recirculated Draft EIR institutes one mitigation measure, MM 4.3-7, to address Valley Fever.[176] MM 4.3-7 is inadequate and does not incorporate all feasible mitigation to address Valley Fever.

MM 4.3-7 should be revised to include the fuller protections that the County previously devised for the 99 Houghton Industrial Park Project, as set forth in MM 4.3-1 of the recirculated Draft EIR for the project:[177]

- The Owner/operator should be directed to thoroughly clean equipment, vehicles, and other items of dust before they are moved offsite to other work locations.
- Grading and trenching work should be phased so that earthmoving equipment is working ahead or down-wind of workers on the ground. The Owner/operator should be required to describe how it intends to phase work in the required Fugitive Dust Control Plan.
- The area immediately behind grading or trenching equipment should be sprayed with water before ground workers move into the area.
- In the event that a water truck runs out of water before dust is sufficiently dampened, any ground workers that otherwise would be exposed to dust should be directed to leave the area until a full truck resumes water spraying.
- All heavy-duty earth-moving vehicles should be closed-cab and equipped with a HEPA-filtered air system.
- Evidence of required training on how to spot and report the symptoms of Valley Fever and how to properly use personal protective equipment should be provided by the Owner/operator to the Kern County Planning and Natural Resources Department within 24 hours of the training session.

10. The Recirculated Draft EIR fails to adopt all feasible mitigation for cumulatively significant net increases in nonattainment air pollutants, including $PM_{2.5}$.

The Recirculated Draft EIR acknowledges that the CTV I Project will result in a cumulatively considerable net increase of criteria air pollutants for which the San Joaquin Valley has been designated a "nonattainment" area pursuant to applicable state and federal ambient air quality standards. In particular, the Recirculated Draft EIR states that "[t]he project's total emissions would exceed the San Joaquin Valley Air Pollution Control District thresholds for

[176] RDEIR, Vol. 1 at 1-31, 4.3-74.
[177] See 99 Houghton Recirculated Draft EIR at 1-27, 4.3-48 to 4.3-49.

nitrogen oxides (NOx), particulate matter with a diameter of 10 micrometers or less (PM_{10}), and particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$), for which the project region is nonattainment under an applicable federal or State ambient air quality standard."[178]

To address the CTV I Project's significant criteria air pollutant emissions, the Recirculated Draft EIR includes MM 4.3-5, which "requires the execution of a Developer Mitigation Agreement (DMA)" with the Air District.[179] According to the Recirculated Draft EIR: "[t]he implementation of a DMA (MM 4.3-5) to reduce criteria pollutants of NO_X, ROGs, and PM net incremental emissions generated by a project has been incorporated into development projects in the county since 2008."[180]

In several respects, MM 4.3-5 does not meet CEQA's requirement that the County adopt all feasible mitigation, nor does it comply with the requirement of Health and Safety Code section 39741.1(a)(3)(A) that CCS projects "minimize, to the maximum extent technologically feasible, copollutant emissions . . . to ensure that the use of carbon dioxide removal technologies and carbon capture and storage technologies does not have an adverse impact on local air quality and public health, particularly in low-income and disadvantaged communities."

a. The County must approve the DMA and institute other requirements to ensure MM 4.3-5 is enforceable and enforced.

While MM 4.3-5 appropriately requires the Owner/Operator enter into the DMA and pay associated fees due to the Air District prior to the approval of any grading or construction activity, the Measure fails to specify that the agreement must be approved by the County as well, subject to public review and comment. In litigation over Kern County's Oil and Gas Ordinance, courts have found that the specific terms of such an implementing agreement are consequential and must provide for "particular" and "enforceable" mitigation.[181] Further, in correspondence between the County and Air District concerning such agreements, the County has confirmed that it—as lead agency—is ultimately "responsible for the implementation of all mitigation measures."[182] For these reasons, the County must itself review and approve the DMA, subject to the additional steps for community input and public review discussed below.

The County should withhold its approval of the DMA unless and until the California Air Resources Board (CARB) confirms in writing that the DMA meets the requirements of section 39471.1 of the California Health and Safety Code. MM 4.3-5 currently specifies that the DMA

[178] RDEIR, Vol. 1 at 1-12.
[179] RDEIR, Vol. 1 at 4.3-70.
[180] RDEIR, Vol. 1 at 4.3-68.
[181] *King & Gardiner Farms, LLC v. County of Kern* (Fifth District Court of Appeal Case No. F077656, Feb. 25, 2020), Slip Opinion at 67-74; *Vaquero Energy Inc., et al. v. County of Kern, et al.* (Kern County Superior Case No. BCV-15-101645-GP, June 7, 2022), Ruling on Petitions for (Third) Writ of Mandate at 21–23.
[182] Letter from Kern County Planning & Natural Resources Dept. to SJVAPCD (Sept. 15, 2020) at 2; accord Letter from SJVAPCD to County of Kern Planning & Natural Resources Dept. (Oct. 30, 2020) at 2 (stating the Air District "is not responsible for making whole any shortfalls for emission reductions that the District is not able to achieve with the mitigation funds it receives from the County" pursuant to an emissions reduction agreement because "as the lead agency under CEQA," it is the County's "obligation to ensure implementation of all mitigation measures included in the Environmental Impact Report").

"shall be reviewed by the California Air Resources Board for compliance with" section 39741.1 "before execution and adoption,"[183] but does not specify if or how compliance will be confirmed. MM 4.3-9 should be revised to specify that written confirmation of compliance is required.

To ensure that MM 4.3-5 and all the other mitigation measures set forth in the Recirculated Draft EIR are implemented and fully enforceable, the County should specify in the CUPs required by the CTV I Project that compliance is required, with construction as well as subsequent operational activities conditioned upon initial and ongoing compliance.

Further, MM 4.3-5 should be revised to require: (a) reporting by the Owner/operator to verify that actual CTV I Project emissions are consistent with the Recirculated Draft EIR's emissions estimates and the fee paid; (b) reporting by the Air District to confirm that funding by the Owner/operator is sufficient to fund local pollution-reducing projects that, in fact, offset the Project's actual emissions; and (c) a mechanism that requires the Owner/operator to pay a supplemental fee or fees if actual Project emissions exceed the Recirculated Draft EIR's estimates and/or the initial fee proves to be insufficient.

b. MM 4.3-5 is ambiguous about exactly what mitigation is required.

The Recirculated Draft EIR and MM 4.3-5 are not clear about precisely what mitigation will be required under the mitigation measure. MM 4.3-5 states:

> The Owner/operator shall pay fees to fully offset Project emissions of NOx (oxides of nitrogen), ROG (reactive organic gases), PM10 (particulate matter of 10 microns or less in diameter), and PM2.5 (particulate matter of 2.5 microns or less in diameter) (including as applicable mitigating for reactive organic gases by additive reductions of particulate matter of 10 microns or less in diameter) (collectively, "designated criteria emissions") to avoid any net increase in these pollutants.[184]

MM 4.3-5's requirement to "fully offset Project emissions . . . to avoid any net increase in these pollutants" is ambiguous. It is unclear if the County is mandating that, for each air pollutant emitted by the CTV I Project, the DMA will require an equivalent, offsetting reduction in the same air pollutant. Conversely, the County may intend to treat all the criteria air pollutants collectively and interchangeably, with the DMA only required to ensure that the combined sum of all increased criteria air pollutant emissions will be offset by an equivalent reduction in criteria air pollutants—no matter the particular air pollutant reductions achieved. Either way, the Recirculated Draft EIR should be revised to clarify what the terms in the mitigation measure mean. For example, if it is the County's intention to allow reductions in PM_{10} to be credited as mitigation for $PM_{2.5}$ under MM 4.3-5, the Recirculated Draft EIR should clearly say as much so that the public and decisionmakers fully understand how MM 4.3-5 will operate.

[183] RDEIR, Vol. 1 at 4.3-71.
[184] RDEIR, Vol. 1 at 4.3-70.

c. The County must require that increases in $PM_{2.5}$ emissions be offset with commensurate reduction in $PM_{2.5}$.

To the extent the County intends to treat all the criteria air pollutants interchangeably for purposes of mitigation, such an approach fails to ensure that significant increases in particular air pollutants will be reduced, as CEQA requires. In this regard, the conflation of $PM_{2.5}$ and PM_{10} is especially problematic.

In reviewing mitigation for the Kern County Oil and Gas Ordinance, the courts have twice found that treating $PM_{2.5}$ and PM_{10} interchangeably for purposes of mitigation is unlawful. In 2020, the Fifth District Court of Appeal agreed with petitioners that the County's 2015 EIR failed to adequately mitigate $PM_{2.5}$ pollution. Reviewing the issue as a matter of law, the court observed that $PM_{2.5}$ and PM_{10} "are not the same" and faulted the County's mitigation measure and a related emissions reduction agreement for "[l]umping them together."[185] According to the appellate court, absent a finding that it would be infeasible, the County was required to adopt "fully enforceable" mitigation in the form of a "particular requirement" for $PM_{2.5}$.[186]

More recently, in 2022, the Kern County Superior Court again agreed with petitioners that the County unlawfully failed to adopt all feasible mitigation for $PM_{2.5}$ and to make such mitigation enforceable. In its ruling, the court faulted the County for continuing to "conflat[e] … PM2.5 and PM10."[187]

Although MM 4.3-5 mentions both $PM_{2.5}$ and PM_{10} separately, that is insufficient. Instead, MM 4.3-5 should specify that the Project's $PM_{2.5}$ emissions will be mitigated by funding projects that result in an equivalent quantity of $PM_{2.5}$ reductions. Absent such an explicit requirement in MM 4.3-5, significant increases in $PM_{2.5}$ may, in fact, evade mitigation. In its 2020 opinion, the Fifth District explained how this could happen in a detailed hypothetical:

> Suppose that during a proposed project's first year of operation it was estimated to emit 16 tons of PM2.5 and to emit 17 tons of PM10 that was larger than PM2.5. If the project proponent were to enter into offset agreements that reduced PM10 that was larger than PM2.5 by 30 tons in the first year, then the net particulate matter emissions for the first year would be three tons, which is below the standard of significance for both PM10 and PM2.5. However, the 16 tons of PM2.5 emissions would not have been offset and, under Air District's 15-ton per year threshold of significance for that air pollutant, one would conclude that the project would have a significant adverse effect on air quality despite the offsets of PM10.[188]

[185] *King & Gardiner Farms* Slip Opinion at 70–72.
[186] *King & Gardiner Farms* Slip Opinion at 70–73; accord *King & Gardiner Farms*, 45 Cal.App.5th at 830.
[187] *Vaquero Energy*, Ruling on Petitions for (Third) Writ of Mandate at 22.
[188] *King & Gardiner Farms* Slip Opinion at 71.

d. Additional changes are required to ensure that MM 4.3-5 will effectively reduce air quality impacts to the extent feasible.

MM 4.3-5 recognizes the importance of addressing air quality impacts where the CTV I Project's increased air pollution emissions will be experienced most acutely—i.e., in the communities nearest to the proposed Project. MM 4.3-5 therefore appropriately requires that monies collected pursuant to the DMA will be used to fund pollution-reducing mitigation projects within a 20-mile radius.[189]

MM 4.3-5 also responds to the need for outreach to local community members to ensure effective operation of the DMA, requiring the Owner/operator to pay an annual fee "for the creation of a county managed community liaison position to provide technical support to the Eligible CCS Air Funding Communities and coordination with the San Joaquin Valley Air Pollution Control District to expedite use of the funding for air mitigation projects."[190] This likewise is a welcome and appropriate requirement.

Nonetheless, further steps can and should be taken to ensure the DMA effectively reduces air quality impacts. Specifically:

- MM 4.3- should require the Owner/operator and the Air District to establish a community-led steering committee made up of affected residents that live within Eligible CCS Air Funding Communities. The purpose of this steering committee would be to provide input to the Owner/operator and the Air District as the terms of the DMA are developed, and to advise the Air District on its funding decisions once the DMA is executed.
- MM 4.3-5 should also specify that, with the support of the DMA-funded community liaison, the steering committee will hold periodic public meetings and/or workshops to hear residents' concerns and to provide information about the availability of DMA funds.
- In addition to requiring funding for the community liaison position, MM 4.3-5 should also require additional funding to ensure that the public liaison and steering committee can conduct outreach in English as well as Spanish—with an ability to provide written materials in both languages as well as interpretation at meetings and/or workshops.

B. The Recirculated Draft EIR's Analysis and Mitigation of Climate Impacts is Inadequate.

The Recirculated Draft EIR's GHG emissions analysis is unsupported, self-contradicting, and violates CEQA's requirements for proper analysis.

First, the Recirculated Draft EIR's GHG analysis relies on contradictory and false premises: it purports to analyze GHG impacts from future CO_2 sources it also argues are

[189] RDEIR, Vol. 1 at 4.3-71.
[190] RDEIR, Vol. 1 at 4.3-71.

impossible to analyze. Moreover, it claims that these sources will be "hard to decarbonize" while this claim is contradicted by the Recirculated Draft EIR's own evidence.

The analysis is also missing crucial information: it fails to account for all elements of the CTV I Project, fails to analyze the whole Project's lifespan, fails to account for potential life extension of fossil fuel facilities, and does not disclose potential offset credit generation. Finally, the analysis of CO_2 retention in the ground is not supported by the evidence, as the attached DiGiulio Report shows, because it fails to identify permanence standards and ignores crucial leakage risk factors that contradict the claim that CO_2 will remain permanently in the ground.

Second, the GHG analysis reveals a contradiction at the heart of the premise of this Project: the Recirculated Draft EIR's analysis of GHG impacts concludes that even though permanent CO_2 sequestration and reductions in CO_2 emissions are CTV I Project's main objectives, the Project has a potentially significant impact from GHG emissions. Even worse, the Recirculated Draft EIR reaches this conclusion in part based on the assertion that it cannot guarantee that the CO_2 it proposes to inject underground will actually remain underground permanently without release or leakage. No meaningful analysis or evidence supports any of these conclusions in the Recirculated Draft EIR.

Third, the analysis does not adequately assess consistency with plans and policies relating to GHGs, including California's leading plan for GHG emissions reduction, the 2022 Scoping Plan.

Fourth, the Recirculated Draft EIR's cumulative impacts analysis is wholly inadequate, self-contradicting, and fails to address any cumulative projects, which is the essence of a cumulative impacts analysis.

Finally, the Recirculated Draft EIR's mitigation measures are inadequate under CEQA. They are ineffective, unenforceable, and impermissibly deferred without any standards, as required under CEQA. Moreover, some measures rely on offset credits, revealing a fundamental failure in the CTV I Project's ability to meet its objectives.

1. The Recirculated Draft EIR's GHG analysis is inadequate under CEQA.

a. The GHG analysis relies on data it claims does not exist.

One of the basic flaws at the heart of the GHG analysis is that it purports to present data that, according to the same analysis, does not exist. Table 4.8-6 presents "Projected Injection 2026-2045" and claims that total GHG injected in the CTV I Project is projected to be 31,217,430 MT CO2e.[191] This number, however, represents CO_2 injected from many sources beyond the initial sources the Recirculated Draft EIR describes and analyzes—the Elk Hills field gas streams. The GHG analysis does not only provide a total volume of CO_2 injected underground over twenty years. The analysis goes as far as projecting the exact volume of CO_2 that will be injected in each year of the Project's first 20 years of operation.

[191] RDEIR, Vol. 1 at 4.8-26.

At the same time, the same analysis states clearly that because these sources "have not been permitted or completed CEQA, information cannot be provided on the total amount of GHG emissions they produce, how much will be captured, how much stored, how much additional created or how much will still be released to the atmosphere."[192] Both parts of the analysis cannot be true at the same time.

b. The GHG analysis relies on a false premise.

The GHG analysis relies on a premise that is not only vague and unsupported by evidence but is, in fact, contradicted by the Recirculated Draft EIR's own information in a way that renders the whole GHG analysis unsupported and inadequate under CEQA.

Specifically, the Recirculated Draft EIR argues that "[t]he capture of the GHG from the initial source and other sources will reduce the amount of CO_2 in the atmosphere emitted by industries that are essential but hard to decarbonize, such as concrete and hydrogen transportation fuels" and therefore, "[a]ccounting for the GHG emissions reductions from CCS, the project's impacts related to GHG emissions would be less than significant."[193]

The GHG analysis's premise is that if the Project's CO_2 sources are "essential but hard to decarbonize" industries, the Project would be beneficial from a climate perspective and will have a less than significant impact on GHG. This premise is contradicted by the Recirculated Draft EIR's own information and mitigation measures.

The analysis fails to define what are "essential but hard to decarbonize" industries. At the same time, MM 4.11-7 limits future Project sources to a list of sectors and industries. These sectors and industries include "hydrogen—green and blue," biomass carbon removal and storage (BiCRS), cement production, green steel production, oilfield field gas streams, power plants, DAC, and alternative fuel production.[194]

Several sources on this list cannot be categorized as "essential but hard to decarbonize" under any reasonable definition. First, some of them are not industries at all. As explained below, industries in the climate context are usually defined by the end-product or service, like cement or steel. But oil field gas streams, blue hydrogen, and alternative fuels are energy sources, not industries with an essential end-product.

Moreover, the term "hard to decarbonize" is completely irrelevant to fossil fuels (like oil field gas) or fossil fuel-based plants (like gas power plants). These fuels and facilities are not "hard to decarbonize"—they are the very source of CO_2 that decarbonization efforts are aimed at eliminating. CARB's Scoping Plan, which lays out the path to achieve California's climate goals, and which the Recirculated Draft EIR claims to be consistent with,[195] states that the "transition away from fossil combustion" is the plan's overriding goal.[196]

[192] RDEIR, Vol. 1 at 4.8-25.
[193] RDEIR, Vol. 1 at 4.8-26.
[194] RDEIR, Vol. 1 at 4.11-53 to 4.11-54.
[195] RDEIR, Vol. 1 at 4.8-30.
[196] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality* at 183.

The CARB Scoping Plan also includes a discussion of key sectors that it covers, contradicting any suggestion that the full range of industries, fuels, and processes listed as potential CO_2 sources might be considered "hard to decarbonize." Under "Industry," the Scoping Plan's discussion makes a clear distinction between industries and their energy sources and explains that different fossil fuels "provide energy to meet three broad industry needs: electricity, steam, and process heat."[197] It then explains that "[e]lectrification and solar thermal heat are best-suited to industrial processes that have relatively low heat requirements,"[198] but that "[t]here are fewer commercially available and economically viable electrification options to replace industrial processes that require higher-temperature heat."[199] The Scoping Plan goes on to say that "[i]ndustries in California with high heat needs include *steel forging, glass manufacturing*, and industries with calcination processes, such as *manufacturing lime and cement*."[200] It is clear that oil field gas, gas power plants, blue hydrogen, and alternative fuels cannot be treated as "essential but hard to decarbonize" industries under the Scoping Plan, and the premise of the GHG analysis is therefore contradicted by the Recirculated Draft EIR's own mitigation measures.

This contradiction is apparent even in the Recirculated Draft EIR's discussion of potential CO_2 sources. The "Source Identification Memo" ("Source Memo") added to the Recirculated Draft EIR explains that "[d]ue to the high heat required, cement plants are one of a few industries that are hard to decarbonize."[201] When discussing steel plants as potential sources, the Source Memo again explains that "[s]teel forging requires high heat and onsite combustion, with few electrification options to replace fossil gas for high heat requirements, and as such is among the industries hard to decarbonize." The Source Memo makes clear that "hard to decarbonize" industries are those where electrification options are hard to come by to produce the end product. Tellingly, the Source Memo does not use the term "hard to decarbonize" when discussing any other potential sources for the Project, such as gas power plants and hydrogen plants. Any conclusion based on the assertion that the listed sources are "hard to decarbonize" is erroneous and unsupported by substantial evidence.

The "hard to decarbonize industry" definition is also irrelevant to DAC, which is not an industry, but a process aimed at pulling CO_2 from the atmosphere, and to green hydrogen which, as the Source Memo explains, generates no GHG byproducts.[202]

The erroneous use of the "hard to decarbonize" concept in listing potential CO_2 source industries underscores the failure at the heart of the Recirculated Draft EIR's process—in which the County attempts to certify a major carbon injection and storage operation without accounting for its sources and their impacts. The Recirculated Draft EIR must be revised to include a clear and supported definition of "essential but hard to decarbonize" industries and provide evidence that the CTV I Project's future sources fall squarely within the definition.

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[197] *Id*. at 207.
[198] *Id*. at 208.
[199] *Id*. at 209.
[200] *Id*. (emphasis added).
[201] RDEIR, Vol. 2, App'x K.4 - Source Identification Memo at 3.
[202] *Id*.

c. The GHG analysis fails to account for all project elements.

The Recirculated Draft EIR's analysis of GHG emissions is informationally inadequate and lacks substantial evidence to support its conclusions. It fails to disclose the full range of projected emissions from the overall scope of activities relating to the CTV I Project, or even from the full operations of capture and storage activities.

The GHG impact analysis discloses that the County plans to issue entitlements for the whole storage capacity of 49.25 MMT of CO_2, as well as CCS facilities capturing CO_2 from the existing plants (the gas plant and power plant) at the Elk Hills oil field. Future sources, according to the Recirculated Draft EIR, "are required to be permitted with a separate CUP process and environmental review for compliance with CEQA."[203]

The analysis then provides an estimate of the construction and operations emissions. The analysis is provided only for the existing plants and the new capture facilities built for them. Under Table 4.8-4, "Estimated Operational Greenhouse Gas Emissions", the Recirculated Draft EIR presents the expected emissions from the existing plant, the projected emissions from mobile sources of the capture facility, and the projected amounts of CO_2 captured and sequestered until the year 2045.[204] The Recirculated Draft EIR concludes that over 20 years, the Project will result in net emissions reduction of 31,217,430 MT CO_2e.[205]

But the Recirculated Draft EIR fails to disclose the operational emissions from the capture facility *stationary sources*; instead, the document includes only its mobile emissions in Table 4.8-4. This is misleading and inadequate. Section 3.4 of the Recirculated Draft EIR details the proposed Project characteristics. The Project, according to the document, will include two amine plants for the capture process, CO_2 compression and pumping facilities including compressors, pumps, chiller system and heat exchangers,[206] pipelines and pipeline appurtenances, including potential pump stations,[207] and injection facilities that include compression or pumping stations.[208] All these Project components are completely missing from the Project GHG analysis. In addition, the attached expert report of Dr. Ron Sahu notes that the analysis is missing, and should include, GHG emissions associated with the maintenance of equipment, including "blowdown" or similarly necessary emissions in order to allow for proper preventive maintenance.[209] Relatedly, the DiGiulio Report notes that in the Emergency and Remedial Response Plan, CTV discussed venting CO_2 from surface facilities in the event of an emergency, but this potential loss of CO_2 is not accounted for or quantified in the analysis.[210] The analysis must include the projected GHG emissions from *all* Project operations.

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[203] RDEIR, Vol. 1 at 4.8-19.
[204] RDEIR, Vol. 1 at 4.8-23 to 4.8-24 ("Table 4.8-4 shows only the initial source permitted with this EIR (collection of pre-combustion oilfield gas from in-field CRC facilities) at the same rate").
[205] RDEIR, Vol. 1 at 4.8-24.
[206] RDEIR, Vol. 1 at 3-18.
[207] RDEIR, Vol. 1 at 3-20.
[208] RDEIR, Vol. 1 at 3-22.
[209] Sahu Report at 4.
[210] DiGiulio Report at 12.

d. The GHG analysis fails to analyze the whole Project's lifespan.

The Recirculated Draft EIR also fails to explain why the analysis goes only to the year 2045 and up to 31 MMT of CO_2,[211] when the Recirculated Draft EIR seeks to approve the whole storage capacity of almost 50 MMT, and the Project's lifespan is currently estimated to be 30 years (or roughly to 2054),[212] and potentially longer. EPA's docket for the CTV I Project Class VI permit indicates that CTV would be required to implement an EPA-approved Post-Injection Site Care and Site Closure Plan, and that it will include post-injection monitoring for at least 50 years and until it demonstrates non-endangerment of underground sources of drinking water (USDW) based on monitoring and other site data.[213]

The analysis should account for the whole storage capacity the Recirculated Draft EIR is seeking to approve, and for the whole projected life of the related CCS facilities and sources.

e. The GHG analysis fails to account for potential life extension of fossil fuel facilities.

The first proposed source for CO_2 sequestration in the CTV I Project is the pre-combustion Elk Hills oil field gas, which is processed at the natural gas plant (CGP-1) facility and used at the Elk Hills power plant.[214] The GHG analysis assumes continuous operations of the power plant, which is already over 20 years old, at least into the year 2045.[215]

The GHG analysis fails to provide any information about the expected life of the power plant independently of its role as a CO_2 source for the Project, despite acknowledging that California aims to reduce its dependency on fossil fuels.[216] In some places, the Recirculated Draft EIR even assumes continued operations for the 30-year duration of the proposed Project.[217]

As the Sahu Report notes, the proposed Project would require the power plant to operate for over 50 years, while "[w]ithout significant additional investments to extend the life of the power plant, it is likely that the Elk Hills power plant would have shut down but for the proposed project."[218]

Moreover, the sources list in the Recirculated Draft EIR includes both oil field gas streams and power plants—a fossil fuel and a fossil fuel operated facility—as potential sources.[219] The recirculated cumulative projects list includes multiple oil and gas operations as well as two existing gas power plants (in an "unknown" location).[220] The Project's objectives were revised in the Recirculated Draft EIR in a way that raises the concern that the Project will

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[211] RDEIR, Vol. 1 at 4.8-24.
[212] RDEIR, Vol. 1 at 4.2-14.
[213] EPA, *Public Comments Sought on Class VI UIC Injection Well Carbon Storage Draft Permits* at 4–5.
[214] RDEIR, Vol. 1 at 3-1.
[215] Cal. Energy Com. (CEC), *Elk Hills Power Project* (last accessed July 15, 2024), https://www.energy.ca.gov/powerplant/combined-cycle/elk-hills-power-project.
[216] RDEIR, Vol. 1 at 4.8-24.
[217] Sahu Report at 3
[218] Sahu Report at 3–4.
[219] RDEIR, Vol. 1 at 3-13.
[220] RDEIR, Vol. 1 at 3-45 to 3-47.

serve to extend the life of fossil fuels—and in fact suggests that is a specific objective of the project: the Project's objective of contributing to CRC's "adopted goals of Full-Scope Net Zero emissions" is now qualified by the sentence "by capturing and storing CO_2 emissions from CRC's Elk Hills field gas operations."[221]

The Recirculated Draft EIR fails to address the critical question of whether the CTV I Project may facilitate extending the life of the Elk Hills power plant or of any other fossil fuel source, and the resulting GHG emissions implications.

f. The GHG analysis does not disclose potential offset credit generation.

The Recirculated Draft EIR does not discuss or disclose whether Project proponents believe its operations will—or should—receive credit as offsets in the cap-and-trade market. A recent report by the Independent Emissions Market Advisory Committee noted that "there are conflicting views on whether carbon dioxide removals should be given credit as offsets in the cap-and-trade market and resolving this will be an important issue for CARB and the legislature."[222] CRC's presentation regarding the CTV I Project from November 2023 states that "[t]he capture project is targeting 45Q credit generation as well as the potential for LCFS qualification and Cap & Trade (C&T) avoidance."[223]

The question of whether the CTV I Project can generate offset credits is crucial for a full analysis of the Project's impacts. If the Project is allowed to generate credits, it means its overall GHG impacts will be materially different than those claimed under the GHG analysis, as its operation may allow for continued emissions elsewhere. The analysis must disclose and analyze the issue of offset credits generation by the Project.

g. The GHG analysis is not supported by the evidence.

The Recirculated Draft EIR's analysis for Impact 4.8-1, "Generate Greenhouse Gas Emissions, Either Directly or Indirectly, that may have a Significant Impact on the Environment," is unsupported by substantial evidence and internally contradictory. This analysis assumes that unless "any of the injected CO_2 leak at injection," or "additional, unmitigated GHG emissions be created from the capture facility operations," the injected CO_2 will remain in the reservoirs, resulting in reduction of CO_2 emitted by the CO_2 source industries.[224] The Recirculated Draft EIR also, however, acknowledges briefly that leaks might happen "at injection." And even more confusingly, the document makes a significance finding based on the acknowledged (and vaguely-stated) risk of a GHG "release due to unforeseen circumstances or equipment failure."[225] Moreover, as the DiGiulio Report shows, to the extent the Recirculated Draft EIR relies on the assumption that stored CO_2 will actually both reach and remain in the reservoirs as required for the Project to meet its objectives, that assumption suffers from two major flaws. First, it does not rely on any clear standard to support the analysis and the

[221] RDEIR, Vol. 1 at 3-7.
[222] Independent Emissions Market Advisory Committee, *2023 Annual Report* (Feb. 2024) at 27.
[223] CRC and CTV, *Third Quarter 2023 Results* (Nov. 01, 2023).
[224] RDEIR, Vol. 1 at 4.8-26.
[225] RDEIR, Vol. 1 at 4.8-26.

conclusion that CO_2 will be permanently retained in the ground. Second, it is not supported by the evidence, and is often contradicted by it.

In his report, Dr. DiGiulio explains that "[a] permanence standard should be established in the recirculated DEIR to determine the effectiveness and impact of the project. In the absence of a permanence standard, there is no metric to determine whether CO_2 is permanently retained."[226] Dr. DiGiulio explains that the EPA standards are aimed at water protection, and prohibit *any* leakage into the Etchegoin Formation, while CTV refers to the Etchegoin Formation as a "dissipation interval", which means it allows migration from the storage formation.[227] To analyze the Project's potential impacts, therefore, the Recirculated Draft EIR must define its permanence criteria. The Recirculated Draft EIR fails to address this deficiency. Dr. DiGiulio recommends that a permanence criterion be specified as a 95% probability of occurrence that 99% of CO_2 will be retained in the 26R and A1/A2 reservoirs over a period of 100 years. He further recommends that a criterion for leakage to the atmosphere will be specified as a 95% probability of occurrence that 99% of CO_2 will be retained within all subsurface media over a period of 1,000 years.[228]

In addition, Dr. DiGiulio concludes in his report that the information presented in the Recirculated Draft EIR and Class VI permit applications does not support a finding that the Project will have greater than 95% probability that 99% of CO_2 will be retained in the storage reservoirs over a period of 100 years, or even a lower standard set by CARB for crediting purposes under the CCS Protocol.[229] Dr. DiGiulio explains that the retention is not credible due to the large number of wellbore penetrations in the area, the high pressure of storage, the fact the storage will primarily consist of supercritical fluid, and the elevated risk of seismic activity in the vicinity of the Project area.[230]

Dr. DiGiulio explains that leakage of CO_2 from wellbores is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2.[231] Given the large number of well penetrations in the area, a robust evaluation of wellbore integrity of both plugged and unplugged wells prior to injection is required to assess the CO_2 retention.[232] However, as the DiGiulio Report shows, the Recirculated Draft EIR fails to support its conclusions regarding CO_2 retention with evidence.

The full extent of the failure to support the Recirculated Draft EIR's analysis and conclusions with evidence is detailed in the DiGiulio Report. A few examples of that failure are provided below.

First, Dr. DiGiulio shows that the evidence does not support the Recirculated Draft EIR's claims for confinement of CO_2 to storage areas. The Elk Hills oil field is an anticlinal structure. The Recirculated Draft EIR argues that the Monterey Formation in the 26R and A1/A2 storage

[226] DiGiulio Report at 10.
[227] DiGiulio Report at 10.
[228] DiGiulio Report at 11.
[229] DiGiulio Report at 11.
[230] DiGiulio Report at 11.
[231] DiGiulio Report at 14.
[232] DiGiulio Report at 14.

reservoirs have "*minimal*" connection outside the Area of Review. But as Dr. DiGiulio notes, the isolation of injected CO_2 in anticlinal structures is a concern, and the Recirculated Draft EIR fails to provide evidence to show that anticlinal structures in fact provide full containment.[233] In addition, the Recirculated Draft EIR claims that confinement of the Reef Ridge Shale has been demonstrated, because large quantities of gas and water have been injected into the reservoir without leakage over the years. The DiGiulio Report shows this claim suffers from two flaws: first, there is evidence to the contrary. Even more importantly, there is no evidence of how and if leakage was even monitored, and thus no support for the conclusion that gas and water that were injected in the past did not leak.[234]

As stated above, a major issue highlighted in Dr. DiGiulio's report is the Recirculated Draft EIR's failure to properly evaluate the current well penetrations from legacy oil and gas wells and the risk of leakage they pose. Dr. DiGiulio shows that wellbore integrity failure is common, and that such failure is not necessarily addressed through well plugging and can persist after the well is "properly" plugged.[235]

Dr. DiGiulio shows that despite the fact CTV identified 204 wellbores in the 26R reservoir and 150 wellbores in the A1/A2 reservoirs, no wellbores were deemed deficient by CTV in either reservoir and none require corrective action. As Dr. DiGiulio notes, this 0% wellbore barrier failure rate for 354 wellbores "is at odds with the published rates of wellbore failure rates ranging from 2-75% in the literature."[236] At the same time, no information that will enable verifying the accuracy of this statement is provided in the Recirculated Draft EIR. As Dr. DiGiulio explains, because the plugged wells at the Project site are expected to contain highly pressurized supercritical CO_2 for hundreds, if not thousands of years, "the County should not ignore the serious gaps in the existing regulatory framework and must require full investigation and remediation" of these wells.[237] The Recirculated Draft EIR must be revised to include all relevant information, including but not limited to wellbore diagrams, cement evaluation logs, and internal and external mechanical integrity tests, to support its conclusions with evidence.[238]

Moreover, Dr. DiGiulio notes that CTV states that there are 150 wellbores in the A1/A2 storage reservoir penetrating the Reef Ridge shale. Seventy-nine of these are currently unplugged wellbores and CTV states that 33 wells in the A1/A2 reservoir have been identified for abandonment. Accounting for these wells and 6 more that will be reconfigured, Dr. DiGiulio finds there are 40 more wells that are unaccounted for in the Recirculated Draft EIR.[239]

Dr. DiGiulio also explains that wellbore schematics are "absolutely vital" in understanding the need or potential need for corrective action, but that since CTV claimed that these schematics are business confidential information, this information is not available to those reviewing the Recirculated Draft EIR. The information on plugging locations that is now provided in Appendix 2 in the Recirculated DEIR is not a substitute for wellbore schematics, and

[233] DiGiulio Report at 6–7.
[234] DiGiulio Report at 8.
[235] DiGiulio Report at 14.
[236] DiGiulio Report at 16–17.
[237] DiGiulio Report at 14–15.
[238] DiGiulio Report at 17.
[239] DiGiulio Report at 15.

CTV should make all information associated with wellbores relevant to wellbore integrity publicly available.[240]

Finally, the DiGiulio Report highlights the fact that the Recirculated Draft EIR "is replete with vague terms that lack definitions and measurable standards."[241] The technical documents often use terms like "adequate" and "sufficient" in places where exact, measurable definitions are necessary for a proper analysis. As an example, the Recirculated Draft EIR argues that all wells within the Area of Review in the A1/A2 reservoir are protective of the USDW because there is "sufficient" annular cement within the confining Reef Ridge Shale. But what "sufficient" means in this context is left undefined.[242] In other places, wells are described as being in "adequate" condition regarding annular isolation, without any explanation of what "adequate" is.[243] Dr. DiGiulio highlights multiple such uses of vague and undefined terms that must be clarified to allow for proper review of the Recirculated Draft EIR and guarantee its conclusions are supported by the evidence.

In sum, the analysis takes credit for the potential CO_2 storage of the Project, but fails to support the conclusion that CO_2 will be retained in the ground with evidence.

2. The Recirculated Draft EIR's halfhearted and contradictory finding of potentially significant GHG impacts violates CEQA.

The Recirculated Draft EIR's conclusions and findings regarding the significance of GHG impacts are incoherent and internally contradictory, finding at once both that GHG emissions impacts are, and are not, significant. The finding of significant impact, specifically, is not accompanied by any data or analysis describing or analyzing the nature or extent of the significant impact, and the document also appears to deny that this impact exists alongside its disclosure of the impact. These conclusions and findings cannot, by their own terms, be informationally adequate, nor are they supported by substantial evidence. The document should instead provide a detailed analysis of impacts supporting its finding, as set forth below.

The environmental analysis finds that "[a]ccounting for the GHG emissions reductions from CCS, the Project's impacts related to GHG emissions would be less than significant."[244] But then it goes on to make a significance finding, saying:

> However, the estimated reductions are contingent upon injected CO_2 remaining in the identified geographically confined reservoirs for storage in perpetuity without leakage from injection and capture activities. Should any of the injected CO_2 leak at injection or additional, unmitigated GHG emissions be created from the capture facility operations, then GHG emissions from the project would be potentially significant.[245]

[240] DiGiulio Report at 16.
[241] DiGiulio Report at 15.
[242] DiGiulio Report at 15.
[243] DiGiulio Report at 15–16.
[244] RDEIR, Vol. 1 at 4.8-26.
[245] RDEIR, Vol. 1 at 4.8-26.

With this brief statement, the Recirculated Draft EIR concludes that despite implementation of several mitigation measures, "the possibility of a release due to unforeseen circumstances or equipment failure remains" and the CTV I Project's impacts from GHG emissions "remain significant and unavoidable."[246] This specific acknowledgment of significant impact from the risk of unintended releases of GHGs is articulated in the Recirculated Draft EIR's GHG impacts section as one of the rationales for the GHG significance finding, but is not included in the summary of impacts in Table 1.1.[247] Moreover, as discussed more fully above and in the DiGiulio Report, the Recirculated Draft EIR's impact analysis fails to properly disclose and analyze this risk.

First, if this conclusion is correct—if the Project may have a significant (negative) impact on GHG emissions because of the risk of release from failure at any stage in Project operations—then the County should not approve the CTV I Project, as it does not fulfill its fundamental objective: to capture and permanently store CO_2 emissions underground.

Second, the Recirculated Draft EIR's handling of this issue violates CEQA. The document attempts to avoid accounting for the Project's impacts by acknowledging the possibility of leakage and finding that risk to be a significant and unavoidable impact, and at the same time failing to include any analysis of the nature, extent, or magnitude of this risk—and elsewhere the Recirculated Draft EIR appears to deny the risk even exists. The document thus does not comply with CEQA's requirement that an EIR will "be prepared with a sufficient degree of analysis to provide decisionmakers with information which enables them to make a decision which intelligently takes account of environmental consequences."[248] And the conclusions are thus not supported by substantial evidence.

The courts are clear that "[A]n EIR's designation of a particular adverse environmental effect as 'significant' does not excuse the EIR's failure to reasonably describe the nature and magnitude of the adverse effect."[249] Yet the Recirculated Draft EIR does exactly that. The GHG discussion makes no reasonable effort "to explain the nature and magnitude of the impact" from GHG leakage, as CEQA requires.[250] It includes no information regarding the probability of CO_2 leakage, the circumstances under which it might happen, the potential magnitude of such leakage, or its impacts on GHG emissions. It simply classifies the impact as significant and unavoidable without any meaningful discussion. By doing so, it also violates the rule set by the courts that an EIR must set forth the bases for its findings; a bare conclusion regarding an environmental impact without an explanation of its factual and analytical basis is not sufficient.[251]

As stated in the DiGiulio Report, CO_2 leakage from geologic storage is bound to occur, and "the important question is not whether there will be leakage, but whether the extent of

[246] *Id*.
[247] RDEIR, Vol. 1 at 1-13.
[248] *Sierra Club, supra*, 6 Cal.5th 502 at 514.
[249] *Cleveland Nat'l Forest Found. v. San Diego Assn. of Governments* (2017) 3 Cal.5th 497, 514.
[250] *Sierra Club, supra*, 6 Cal.5th 502 at 519.
[251] *Laurel Heights*, *supra*, 47 Cal.3d at 404.

leakage is acceptable […] and how leakage will be monitored and quantitated."[252] The Recirculated Draft EIR fails to do just that.

There are several leakage risks that a proper analysis must account for and analyze. First, the risk of leakage from well penetration: the DiGiulio Report explains that research shows that more than 8 wells/km^2 concentrations are considered worst case scenario regarding CO_2 retention in the ground.[253] The presence of 354 well penetrations in the storage area leads to a well penetration density of 9.6 wells/km^2, which represents a worst-case scenario for permanence for geologic storage of CO_2.[254] The Recirculated Draft EIR must be revised to include a robust evaluation of wellbore integrity of both plugged and unplugged wells, to properly reflect the risk of leakage from these wells.

Leakage from wellbores can also manifest in the form of a CO_2 well blowout.[255] Despite the fact that release of CO_2 from an injection well or failed plugged or unplugged wellbores could be catastrophic depending on surface topography and meteorologic conditions, the Recirculated Draft EIR fails to discuss the probability of such an event when discussing GHG emissions impacts.[256]

The Recirculated Draft EIR also fails to analyze the issue of lateral confinement to storage areas. As the DiGiulio Report shows, there is no evidence to support the assumption that CO_2 stored in reservoirs will in fact be confined and will not migrate beyond them.[257] The document must be revised to support these assumptions and assess the risk of leakage from lateral migration.

The DiGiulio Report also shows that the Recirculated Draft EIR's analysis of seismic risk is highly deficient and not supported by the evidence, as it fails to properly account for all factors of seismic risk.[258] The flaws in the Recirculated Draft EIR's seismic analysis are discussed in detail below. However, as explained in the DiGiulio Report, the effects of natural or induced seismicity are of particular concern at the CTV I Project, due to its effect on wellbores, which can occur even after a well is permanently plugged and abandoned. The Recirculated Draft EIR must be revised to properly account for the seismicity risks, and once this is done, to properly account for the risk of CO_2 leakage resulting from seismic activity.

The Recirculated Draft EIR's GHG analysis must be revised to include an accurate, meaningful discussion of GHG impacts that is supported by the evidence, and this evidence-supported analysis must reflect a consistent conclusion as to the nature, magnitude, and significance of the impact.

[252] DiGiulio Report at 9.
[253] DiGiulio Report at 9.
[254] DiGiulio Report at 9.
[255] DiGiulio Report at 4.
[256] DiGiulio Report at 5.
[257] DiGiulio Report at 6–9.
[258] DiGiulio Report at 25.

3. The Recirculated Draft EIR's GHG consistency analysis is inadequate under CEQA.

Under Impact 4.8-2, the Recirculated Draft EIR purports to analyze whether the Project will conflict with any applicable plan, policy, or regulation adopted for the purpose of reducing the emissions of greenhouse gas.[259] Under this impact area, the Recirculated Draft EIR first analyzes the CTV I Project's consistency with CARB's 2022 Scoping Plan.[260] The Scoping Plan analysis is inadequate under CEQA. Not only is it short, generic, and superficial, but it also fails to address important ways in which the Project is not consistent with the Scoping Plan.

The Recirculated Draft EIR's consistency analysis is made up of a few paragraphs generally describing the Scoping Plan discussion of carbon capture, removal and sequestration, followed by a bullet point list of the Scoping Plan's "Strategies for Success" in the sector, and ending with a single paragraph stating flatly that the Project "would support the Strategies for Success identified in the CARB 2022 Scoping Plan," "would comply with any new regulations developed as a result of implementation of the identified Strategies" and "is reasonably expected to reduce region wide and Statewide GHG emissions." The paragraph concludes with no further discussion to show the Project would be consistent with the CARB 2022 Scoping Plan.[261]

First, the analysis is generic. It fails to provide the reader with "sufficient information to foster informed public participation and to enable the decision makers to consider the environmental factors necessary to make a reasoned decision,"[262] as required under CEQA. The analysis also fails to provide substantial evidence to support its conclusions. Except for flatly declaring consistency, the analysis does not address any of the Scoping Plan Strategies beyond simply listing them. It fails to make a connection between the Strategies and the Project, and explain how the Project is consistent with them, or how they are even relevant to the Project. Just as an example, the identified Strategies that call for the state to "Evaluate and streamline permitting barriers to project implementation while protecting public health and the environment" and to "update the CARB Carbon Capture and Sequestration Protocol with the best available science and implementation experience" have nothing to do with the Project.

Second, the analysis fails to address the crucial issue of the Project's CO_2 sources' consistency with the Scoping Plan. The Scoping Plan states that CCS is included in the Scoping Plan "to address emissions from limited sectors, including electricity generation, cement production facilities, and refineries."[263] The Scoping Plan also discusses implementation in the electricity sector in or before 2045 as well as the potential to support hydrogen production.[264] As discussed above, the Recirculated Draft EIR fails to provide information regarding its future CO_2 sources and therefore cannot conclude the Project is consistent with the Scoping Plan. Moreover, the only disclosed CO_2 source in the Recirculated Draft EIR is the pre-combustion Elk Hills oil field gas which provides about one third of its power for oil field operations—not even a sector

[259] RDEIR, Vol. 1 at 4.8-28.
[260] RDEIR, Vol. 1 at 4.8-28 to 4.8-30.
[261] RDEIR, Vol. 1 at 4.8-30.
[262] *Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs*, 91 Cal.App.4th 1344, 1356, 111 Cal. Rptr. 2d 598, 606 (2001), as modified on denial of reh'g (Sept. 26, 2001).
[263] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality* at 86.
[264] *Id.*

the Scoping Plan lists for CCS implementation. The Recirculated Draft EIR's conclusion that the CTV I Project is consistent with the Scoping Plan is therefore unsupported by the evidence and also contradicted by it.

Finally, the Recirculated Draft EIR fails to address the fact that the CTV I Project's proposed mitigation measures are inconsistent with the Scoping Plan. As discussed below, a primary mitigation measure proposed in the Recirculated Draft EIR, in addition to monitoring plans and compliance with regulations, is buying credits to offset GHG emissions.[265] However, the Scoping Plan makes clear that GHG mitigation measures come in a hierarchical order: first, the lead agency must "exhaust[] all the on-site GHG" mitigation. Then, "CARB recommends prioritizing local, off-site GHG mitigation measures" and only then use "non-local off-site mitigation, and voluntary offsets issued by a recognized and reputable voluntary carbon registry."[266] As discussed below, the Recirculated Draft EIR fails to comply with the requirement that offsets will be issued by a recognized and reputable registry, and it also fails to exhaust, or even discuss, all onsite GHG mitigation and other local measures. Finally, it fails to acknowledge and discuss the fact that by improperly relying on offsets, it is inconsistent with the Scoping Plan.

4. The Recirculated Draft EIR fails to analyze and mitigate cumulatively considerable GHG emissions impacts.

The Recirculated Draft EIR's analysis of the CTV I Project's cumulative GHG emissions impacts suffers from many of the same flaws pointed out above regarding its project-level analysis, and from several other serious flaws. The document must be revised to correct these flaws before any decision can be made regarding the Project.

First, there are basic misstatements and inconsistencies that call the analysis into question. As one example, the analysis claims that "Table 4.8-3 shows total GHG reductions of 3,967,977 MT CO_2e over 20 years from implementation of the project".[267] In fact, Table 4.8-3 shows the estimated construction GHG emissions, not total reductions,[268] and those projected reductions of the Project, according to the other tables in the GHG analysis, are 31,217,430 MT CO_2e over 20 years, not 3,967,977 as stated in the cumulative analysis.[269]

Moreover, the Recirculated Draft EIR frames its cumulative GHG analysis in fundamentally misleading ways. For example, the document includes the following statement: "Since the project individually results in a net reduction in GHG emissions, the project would also contribute to reductions in cumulative GHG emissions."[270] First, this statement directly contradicts the Recirculated Draft EIR's cumulative GHG significance finding, which concludes

[265] RDEIR, Vol. 1 at 4.8-27 to 4.8-28.
[266] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality* at 270–71.
[267] RDEIR, Vol. 1 at 4.8-32.
[268] RDEIR, Vol. 1 at 4.8-22.
[269] RDEIR, Vol. 1 at 4.8-24.
[270] RDEIR, Vol. 1 at 4.8-32.

that the Project will contribute to cumulatively considerable significant GHG emissions.[271] And second, this statement completely misses the point of cumulative impact analysis: that "environmental damage often occurs incrementally from a variety of small sources [that] appear insignificant when considered individually, but assume threatening dimensions when considered collectively with other sources with which they interact."[272] In other words, if a CEQA analysis could infer a project's cumulative impacts directly from its individual impact, there would be no need for a cumulative impact analysis at all.

Another major flaw is that the cumulative impacts analysis fails to analyze the CTV I Project's cumulative *projects*. Under CEQA, cumulative impact analysis requires consideration of "other projects causing related impacts,"[273] including "probable future projects."[274] The Recirculated Draft EIR provides a list of cumulative projects under its project description section, but it fails to analyze their impacts in the GHG analysis, claiming that "information cannot be provided" regarding their potential GHG impacts.[275] This claim is not supported by the evidence and is in fact contradicted by it, as discussed above. The cumulative impacts analysis must analyze the projects in its cumulative projects list, as well as any probable future project that plans on sending CO_2 for sequestration at the CTV I Project (as discussed in detail above in the discussion of project description and below in this letter's section on cumulative impacts analysis).

Instead of discussing the cumulative projects the Recirculated Draft EIR discloses, the Recirculated Draft EIR focuses on the CTV I Project's cumulative impacts together with the impacts of "past, present and reasonably foreseeable future oil and gas development including wells and abandonment activity," explaining this focus is "[d]ue to the proposed project's location within an existing oil and gas field."[276] This is underinclusive. While geographic proximity can be a factor in identifying cumulative projects, it is not the only determinative factor.[277]

The Recirculated Draft EIR fails to explain why it focuses on the cumulative impacts of the CTV I Project with only the oil and gas development. It is riddled with vague statements like "impacts from oil and gas development in Kern County on cumulative GHG emissions were determined to remain significant and unavoidable despite implementation of mitigation measures"[278] that lack any explanation as to their relevance to the CTV I Project's cumulative analysis. Potentially, there is a connection between the oil field operations and CTV I because of the Project's usage of depleted oil and gas reservoirs, but that cannot explain the analysis, since the depleted reservoirs are already identified. It is unclear whether this connection stems from plans to sequester more CO_2 sourced from oil and gas production. The Recirculated Draft EIR

[271] See, e.g., RDEIR, Vol. 1 at 1-13 ("The project's cumulative contribution to GHG emissions after implementation of the recommended mitigation measures would remain cumulatively significant and unavoidable").
[272] *Communities for a Better Env't v. Cal. Resources Agency* (2002) 103 Cal.App.4th 98, 114, 126.
[273] CEQA Guidelines, § 15130(a)(1).
[274] CEQA Guidelines, § 15130(b)(1)(A).
[275] RDEIR, Vol. 1 at 4.8-25.
[276] RDEIR, Vol. 1 at 4.8-31.
[277] CEQA Guidelines, § 15130(b)(1)(A).
[278] RDEIR, Vol. 1 at 4.8-32.

must be revised to clarify this point, as well as the rest of the connection between the Project and future oil and gas development.

The Recirculated Draft EIR's cumulative GHG impact analysis is legally inadequate, not supported by substantial evidence, and must be revised to address all the inaccuracies, inconsistencies, and unsupported assumptions, include all relevant cumulative projects, and explain its analysis.

5. The Recirculated Draft EIR does not provide adequate mitigation for GHG impacts.

The GHG mitigation measures identified in the Recirculated Draft EIR fail to meet CEQA's standards for effective, enforceable mitigation. The proposed measures are ineffective, unenforceable, and vague, and there is no evidence to support their efficacy. To the extent some of the vagueness will be clarified in the future, the document also illegally defers that mitigation.

Under CEQA, proposed mitigation measures must be "fully enforceable" through permit conditions, agreements, or other legally binding instruments.[279] Any proposed mitigation must also provide assurance that such implementation will in fact occur.[280] The proposed measures fail on all counts.

a. MM 4.8-1 constitutes inadequate and unlawfully deferred mitigation.

To mitigate what the Recirculated Draft EIR finds to be a potentially significant impact from GHG emissions, it proposes a monitoring plan under MM 4.8-1. This Mitigation Measure requires that prior to injection, the owner/operator will submit "a monitoring plan that complies with all requirements of the EPA UIC permit" for the Project, to demonstrate the retention of the CO_2 in the reservoir. The Measure states that the plan shall be submitted to the County, concurrent with submittal to the EPA for review, and that "[a] copy of the final approved plan from the EPA shall be provided to the Kern County Planning and Natural Resources Department."[281]

Given how crucial it is to guarantee that CO_2 stored in the reservoir will remain there, both for mitigating a potentially significant impact and for achieving the Project's stated goal of CO_2 storage, it would be expected the Recirculated Draft EIR will develop a robust monitoring plan. However, the proposed Mitigation Measure is anything but robust.

In fact, all this Mitigation Measure does is reiterate an already existing rule—that CCS projects that receive a UIC permit from the EPA must prepare a monitoring, reporting, and verification (MRV) plan and submit it for the EPA's approval.[282] This Measure adds nothing to this rule except requiring that a copy of the approved plan will be provided to the County.

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[279] Pub. Resources Code, § 21081.6(b); CEQA Guidelines, §15126.4(a)(2).
[280] *Anderson First Coalition v. City of Anderson* (2005) 130 Cal.App.4th 1173, 1186–87.
[281] RDEIR, Vol. 1 at 4.8-27.
[282] 40 C.F.R § 98.448.

Relying solely on the future EPA MRV plan is inadequate under CEQA and constitutes an impermissible deferral of mitigation. The EPA UIC permit is issued under the Safe Drinking Water Act. As a result, it does not, and cannot, cover all relevant aspects of monitoring for CO_2 leakage.[283] Specifically, Dr. DiGiulio notes that the monitoring plan submitted for the Project in the Class VI permit applications does not directly consider leakage from well penetrations—although this is the most likely source of loss of CO_2. The measure must include a monitoring program specific to evaluating leakage from plugged well penetrations.[284]

A major flaw in relying on EPA's MRV plan is the fact that these plans lack clear performance standards. CEQA allows for details to be developed in future time, as long as the agency adopts specific performance standards the mitigation will achieve.[285] MRV plans that were developed under the EPA permit program have been heavily criticized for failing to include specific monitoring strategies, for containing ambiguous language, and for being difficult to verify and enforce.[286] By relying on EPA's future MRV plan for the CTV I Project, the Recirculated Draft EIR impermissibly defers its mitigation.

The DiGiulio Report makes clear why reliance on the EPA MRV plan fails to comply with CEQA's requirement for effective mitigation. For example, Dr. DiGiulio notes that continuous monitoring in the Etchegoin Formation is important to detect leakage, but further notes that under the EPA permit application, there will be only one such well in each reservoir. A proper monitoring plan should analyze and support the number of required monitoring wells above confining zones to guarantee effective detection of leakage.[287]

The DiGiulio Report finds that the Recirculated DEIR "is replete with vague terms that lack definitions and measurable standards",[288] and this problem is manifested in the proposed mitigation as well. For example, in the Corrective Action Plan filed with the EPA, CTV states that all wellbores within the Area of Review will be pressure tested prior to abandonment and will be reviewed to demonstrate adequate confinement "if necessary" and "if conditions allow." As Dr. DiGiulio notes, these statements are far too vague to be of any use,[289] and thus reliance on the plan cannot serve as enforceable and effective mitigation.

Finally, the requirement to submit a monitoring plan "[p]rior to any injection of CO_2"[290] is vague and unenforceable. CO_2 injection will be ongoing in the CTV I Project. The Measure must be revised to clarify at what point exactly a monitoring plan should be submitted, clarify that the approval of such a monitoring plan will be a condition on each new injection from each source, and clarify and guarantee the means of enforcing the plan.

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[283] DiGiulio Report at 10–11.
[284] DiGiulio Report at 18.
[285] CEQA Guidelines, § 15126.4(a)(1)(B).
[286] Environmental Integrity Project, *Flaws in EPA's Monitoring and Verification of Carbon Capture Projects* (Dec. 2023), https://environmentalintegrity.org/news/epas-rules-for-verifying-carbon-capture-projects-are-riddled-with-holes/.
[287] DiGiulio Report at 17.
[288] DiGiulio Report at 15.
[289] DiGiulio Report at 17.
[290] RDEIR, Vol. 1 at 4.8-27.

In particular, MM 4.8-1 must be revised to include a monitoring plan that will effectively address the potentially significant impact of CO_2 leakage or other release from the CTV I Project. As explained in the DiGiulio Report, such monitoring program should be specific to evaluating leakage from plugged well penetrations as general air monitoring may not be sufficiently sensitive to determine leakage.[291] To the extent the revised measure is lacking any specific elements or details, it must at a minimum identify performance standards to be used in developing it, as required under CEQA.[292] Given the potential impacts of the GHG emissions from the Project, it is also crucial that the monitoring plan will be open for public comments and will require the approval of CARB in addition to the County.

Finally, and crucially, a monitoring plan alone will not fully mitigate the risk of leakage or release to the extent feasible. GHG mitigation measures must also include an action plan that addresses what will happen to address any release, mitigate fully the emissions from any release, and ensure the integrity of the reservoir and overall storage mechanism.

b. MM 4.8-6 is an ineffective, unenforceable, and impermissibly deferred mitigation measure.

The first part of MM 4.8-6 states as follows:

> The project shall offset all greenhouse gas emissions associated with the capture facility, and construction equipment not covered by the Cap and-Trade program or other mandatory greenhouse gas emission reduction measures through owner/operator reductions of greenhouse gas emissions as verified by the San Joaquin Valley Air Pollution Control District, through acquisition of offset credits from the California Air Pollution Control Officers Association Exchange Register or other third party greenhouse gas reductions as verified by the San Joaquin Valley Air Pollution Control District, or through inclusion in an Emission Reduction Agreement, to offset Project-related greenhouse gas emissions that are not included in the Cap-and-Trade program to assure that no net increase in greenhouse gas emissions from the Project construction or operation occur. [293]

In essence, this Measure purports to offset any GHG operational emissions "associated with" the Project's capture facility (as well as some construction emissions) using the tool of emission credits, and claims to thus achieve a "no net increase" in GHG emissions from the Project construction or operations. This Measure is not only inappropriate and unlawful as mitigation, but also reveals a fundamental failure in the Project's ability to meet its objectives.

c. MM 4.8-6 goes against the Project's fundamental premises and objectives.

The CTV I Project is a carbon sequestration project. Its main goals are to permanently store CO_2 in the ground and support California's climate goals.[294] But MM 4.8-6 proposes to

[291] DiGiulio Report at 18.
[292] CEQA Guidelines, § 15126.4(a)(1)(B)
[293] RDEIR, Vol. 1 at 4.8-27 to 4.8-28.
[294] RDEIR, Vol. 1 at 3-7.

allow the Project to allow "acquisition of offset credits from the California Air Pollution Control Officers Association Exchange Register or other third party greenhouse gas reductions as verified by the San Joaquin Valley Air Pollution Control District", to offset any "emissions associated with the capture facility" and "to offset Project-related greenhouse gas emissions that are not included in the Cap-and-Trade program to assure that no net increase in greenhouse gas emissions from the Project construction or operation occur."[295] This Measure thus contemplates that the Project and associated facilities may emit substantial amounts of GHG emissions—potentially without limit—into the atmosphere, as long as they purportedly offset these emissions with emissions credits.

The notion of a carbon sequestration project that may use carbon credits to offset its own emissions is absurd, and undercuts the rationale behind carbon sequestration. An effective carbon sequestration project should be the place where CO_2 is being put in the ground physically and permanently, not a link in a chain of offsets that creates profits for its owners and harm to the public and the environment.

If a CO_2 sequestration project is allowed to offset its emissions through acquisition of offset credits, then the following scenario is possible: A GHG emitting facility that is looking to mitigate its GHG emissions can go and buy offset credits from certain registries. Alternatively, and higher in the hierarchy of preferred mitigation, that facility can send its CO_2 for sequestration at the CTV I Project and achieve the same GHG mitigation goals. The facility chooses sequestration, theoretically putting the CO_2 in the ground permanently. But the CO_2 the facility sends to CTV I may not stay in the ground; instead, CTV I may purchase the same offset credits the emitting facility could have bought in the first place, to offset the emissions from its sequestration project. The futility of this scenario is clear even before going into the many problems with relying on carbon offsets and before considering the added emissions from CO_2 transportation and the operations of the CTV I Project.

d. MM 4.8-6's reliance on offset credits is not supported by the evidence.

Under CEQA, an agency must have specific evidentiary support for a conclusion that mitigation will be effective.[296] The Recirculated Draft EIR lacks evidentiary support, however, that offset credits can achieve emission reductions.

Offset programs, in general, are a contentious tool for curbing GHG emissions, and there is mounting criticism in the scientific and environmental communities against using credits in the effort to stop climate change.[297] Research shows that nature-based solutions cannot effectively offset fossil fuel combustion due to the different nature of CO_2 emissions in the two

[295] RDEIR, Vol. 1 at 4.8-27 to 4.8-28.
[296] See, e.g., *Sierra Club v. County of San Diego* (2014) 231 Cal.App.4th 1152, 1168.
[297] Amazon Watch, *Statement: Offsets Don't Stop Climate Change* (Oct. 6, 2021), https://amazonwatch.org/news/2021/1006-statement-offsets-dont-stop-climate-change.

categories,[298] and offsets are likely to increase GHG emissions rather than decrease them.[299] Environmental justice advocates have pointed out that offsets perpetuate environmental injustice by increasing the relative burden of pollution on already overburdened communities, including low-income communities of color, while GHG reduction is happening, if at all, elsewhere. [300]

There is also a consensus that, to be effective, offsets credits must be real, permanent, additional, verifiable, and enforceable.[301] Additionality is especially hard to ascertain: "additional" emission reductions are reductions not otherwise required by law or likely to occur anyway. Assembly Bill (AB) 32, California's landmark GHG reduction statute, clarifies that "additional" means "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."[302] To be "additional," therefore, an offset credit must not result from actions otherwise legally required, *and* it must be in addition to any reduction that would otherwise occur. MM 4.8-6 fails to include any requirement for additionality of credits, nor for any of the requirements listed above, and thus there is no support for the effectiveness of the mitigation measure.

The Recirculated Draft EIR also lacks evidence that there exist any offset programs capable of ensuring that offsets are "additional." This is a particular concern given that MM 4.8-6 does not include any requirements regarding the offsets' origin, allowing for international offsets, which are especially challenging to verify.[303] There is also no support for the assumption there are enough GHG offset credits available to satisfy the mitigation measures' requirements. This problem is exacerbated by the fact that the Recirculated Draft EIR fails to quantify the volume of emissions that will need to be mitigated using offsets.

e. MM 4.8-6 is ineffective, unenforceable, and impermissibly deferred.

Even if offset credits could be, under certain conditions and limitations, a proper mitigation measure for GHG emissions, and even if they could be acceptable mitigation for a carbon sequestration project, MM 4.8-6 is inadequate as CEQA mitigation.

First, as mentioned above, there are no performance standards for these offsets, and no requirement they will be real, permanent, additional, verifiable, and enforceable. Instead, the measure relies on offsets issues by different parties, including unidentified "third parties," to issue the credits. As courts have recognized, protocols adopted by voluntary market registries may not meet standards necessary to ensure that credits in fact reduce emissions.[304]

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[298] Carton, W. at el, *Undoing Equivalence: Rethinking Carbon Accounting for Just Carbon Removal*, Frontiers in Climate (Apr. 16, 2021), https://www.frontiersin.org/articles/10.3389/fclim.2021.664130/full.
[299] Anderegg, W., *Gambling With the Climate: How Risky of a Bet Are Natural Climate Solutions?,* AGU Advances (July, 22 2021), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2021AV000490.
[300] Amazon Watch, *Statement: Offsets Don't Stop Climate Change*.
[301] *Golden Door Properties, LLC v. County of San Diego* (2020) 50 Cal. App. 5th 467, 511.
[302] Health & Safety Code, § 38562(d)(2).
[303] *Golden Door Properties, LLC*, *supra*, 50 Cal.App.5th 467 at 513.
[304] *Golden Door Properties, LLC*, *supra*, 50 Cal. App. 5th 467 at 511–12.

The only check on any offsets' effectiveness in mitigating GHG impact is the requirement that they will be "verified" by the San Joaquin Valley Air Pollution Control District (SJVAPCD) or through inclusion in an Emission Reduction Agreement. MM 4.8-6 thus impermissibly defers mitigation.[305] By leaving the decision on verification of the credits solely to the judgment of the SJVAPCD, without setting any performance standards and process for the verification and only generally requiring "no net increase," the Measure violates CEQA. "Simply stating a generalized goal for mitigating an impact does not allow the measure to qualify for the exception to the general rule against the deferred formulation of mitigation measures."[306]

The option given in the Mitigation Measure to offset emissions through inclusion in an Emission Reduction Agreement is also invalid under CEQA, for the same reasons. Emission Reduction Agreements are not defined anywhere in the Recirculated Draft EIR in the context of GHG emissions and are used by the Air District for reduction of certain other air pollutants, not GHGs. CARB's review of SJVAPCD Emission Reduction Credit (ERC) System states with respect to GHG that:

> Ultimately, the impact of these GHG ERCs is not clear, as there is no currently authorized use in an NSR context consistent with District rules or in the context of GHG Cap and Trade programs. To CARB's knowledge, none of these GHG ERCs have been used.[307]

Finally, MM 4.8-6 is unenforceable. Mitigation measures must be "fully enforceable through permit conditions, agreements, or other legally binding instruments."[308] Here, the Measure fails to specify in any detail how the Air District will quantify the emissions reductions it needs to achieve, or does achieve, through this measure, the process by which the offsets will be purchased, and proof of their purchase filed, or any enforcement mechanism to ensure that this Measure is actually implemented.

In fact, aside from vaguely stating that the Project "shall offset," the Mitigation Measure fails to state at what point any offset "shall" happen, or whether the Air District or the County will require offsets as a condition of approval of any permit.

The last part of MM 4.8-6 deals with future sources that will be sending CO_2 for injection in one sentence. It summarily states: "All sources providing CO_2 for injection must certify that any additional CO_2 generated from the source capture facility has been mitigated to "no net increase" before injection at Carbon Terra Vault 1."[309]

This part of the Mitigation Measure aimed at future sources suffers from the same severe flaws as described above, only exacerbated. It is entirely ineffective and unenforceable, as it only

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[305] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 856.
[306] *Id.* See also *Sierra Watch v. County of Placer* (2021) 69 Cal.App.5th 86, 110; *Golden Door Properties, LLC*, *supra*, 50 Cal.App.5th 467 at 517.
[307] CARB Enforcement Division, *Review of the San Joaquin Valley Air Pollution Control District Emission Reduction Credit System* (June 2020) at 30, https://ww2.arb.ca.gov/sites/default/files/2020-06/SJV_ERC_FINAL_20200604.pdf
[308] CEQA Guidelines, § 15126.4(a)(1)(B), (a)(2).
[309] RDEIR, Vol. 1 at 4.8-28.

requires vaguely that future CO_2 sources will "certify" that any "additional" CO_2 has been "mitigated to 'no net increase.'" It fails to explain what type of certification can be used and under what conditions, or even to name the agency to whom such "certification" will be submitted and how it will be verified. It also fails to explain what "additional" means in the context of this Measure.

Moreover, the Measure fails to address in any way the carbon generated by *trucks* that will bring CO_2 for injection. As stated before, the Recirculated Draft EIR, though it fails to provide any analysis on the issue, anticipates that some sources will ship their CO_2 using trucks. Such GHG emission sources must be addressed under the document's GHG mitigation measures.

f. MM 4.8-2 through MM 4.8-5 unlawfully rely on reporting requirements or existing or future regulations or plans, without demonstrating these measures meaningfully mitigate Project impacts.

The remaining GHG mitigation measures do not, individually or together, succeed in mitigating GHG impacts.

MM 4.8-2 requires quarterly reporting on the amount of CO_2 injected into the CCS project, and the source of the CO_2.[310] While such reporting is essential, it is not enough, taken together with the other mitigation measures, to mitigate impacts to the extent feasible.

MM 4.8-3 merely requires permitted stationary sources to comply with the Cap-and-Trade regulation and implement Best Performance Standards (BPS) applicable to greenhouse gas reduction for Components at Light Crude Oil and Natural Gas Production, Natural Gas Processing Facilities.[311] But these BPS only apply to certain types of facilities, and if these facilities are not subject to Cap-and-Trade, this mitigation measure will not apply to them at all. Moreover, the Final Staff Report prepared for the SJVAPCD Climate Action Plan states explicitly that "[u]se of performance based standards is not a method of mitigating emissions."[312]

Similarly, MM 4.8-4 and MM 4.8-5 merely require compliance with SJVAPCD regulations (Rule 4401 and 4409) and regulations adopted or amended for methane.[313]

MM 4.8-3, MM 4.8-4, and MM 4.8-5 rely on existing or future regulations, without adding any standards or measures to mitigate potential impacts from GHG emissions. CEQA allows the use of compliance with regulatory standards as mitigation, but only where the regulatory standards ensure actual mitigation of project impacts to the extent feasible. CEQA therefore requires that a determination that compliance will be sufficient to prevent significant

[310] RDEIR, Vol. 1 at 4.8-27.
[311] RDEIR, Vol. 1 at 4.8-27.
[312] SJVAPCD, *Final Staff Report - Climate Change Action Plan: Addressing GHG Emissions Impacts under CEQA* (2009) at 59.
[313] RDEIR, Vol. 1 at 4.8-27.

impacts be based on a project-specific analysis of potential impacts and the effect of regulatory compliance.[314]

C. The Recirculated Draft EIR's Analysis and Mitigation of Energy Use Impacts is Inadequate.

The Recirculated Draft EIR fails to adequately disclose, analyze, and mitigate the CTV I Project's impacts to energy resources. CEQA Guidelines, Appendix F lays out the following directives for proper discussion of a proposed project's energy impacts in an EIR:

> The goal of conserving energy implies the wise and efficient use of energy. The means of achieving this goal include:
>
> (1) decreasing overall per capita energy consumption,
>
> (2) decreasing reliance on fossil fuels such as coal, natural gas and oil, and
>
> (3) increasing reliance on renewable energy sources.[315]

The analysis required under CEQA thus provides the opportunity for project proponents to evaluate the energy consequences of their decisions.

The Recirculated Draft EIR applies, as a threshold of significance, whether the Project will "result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation."[316] The Recirculated Draft EIR concludes that:

> [C]onstruction activities associated with the proposed project would result in the consumption of petroleum-based fuels. However, there are no unusual project characteristics that would necessitate the use of construction equipment or vehicles that would be less energy efficient than at comparable construction sites in other parts of the state. Therefore, it is expected that construction fuel consumption associated with the proposed project would not be any more inefficient, wasteful, or unnecessary than at other construction sites in the region.[317]

In this conclusion, the Recirculated Draft EIR applies, as a threshold, whether the Project would be "*more* inefficient, wasteful, or unnecessary than at other construction sites in the region." But CEQA instead requires an evaluation of whether this project is energy-efficient, not average; CEQA requires mitigation of impacts to energy consumption, where feasible. The claim that the Project has no significant impact on energy resources is thus not supported by substantial evidence. The EIR should require, for example, use of electricity-powered construction equipment and vehicles in all feasible applications.

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[314] *Californians for Alternatives to Toxics v. Dept. of Food & Agric.* (2005) 136 Cal.App.4th 1.
[315] CEQA Guidelines, Appendix F, § 2.
[316] RDEIR, Vol. 1 at 4.6-12.
[317] RDEIR, Vol. 1 at 4.6-14.

Moreover, the Recirculated Draft EIR does not provide sufficient information or analysis to evaluate the Project's overall relationship to energy consumption, and does not even address this question. CO_2 storage projects will often tend to substitute for, rather than facilitate, decreasing reliance on fossil fuels such as coal, natural gas, and oil. The Project's energy conservation analysis fails for many of the same reasons its project description, GHG impact analysis, and cumulative impact analysis are inadequate. In particular, an analysis that includes information about the relationship between Project CO_2 storage operations and Project CO_2 sources is necessary, to fully disclose and analyze whether and to what extent CTV I will facilitate development and use of fossil fuel infrastructure or extend the life of existing fossil fuel CO_2-emitting industries. The Recirculated Draft EIR's failure to include any meaningful discussion of the Project's CO_2 sources renders the discussion inadequate to evaluate how the Project will decrease reliance on fossil fuels or increase reliance on renewable energy.

D. The Recirculated Draft EIR's Analysis and Mitigation of Geologic Risks is Inadequate.

The Recirculated Draft EIR fails to adequately disclose, analyze, and mitigate the significant geologic impacts of the CTV I Project in this region. These failures are unacceptable given the setting in which the Project may occur and render the Recirculated Draft EIR defective as an informational document.

The expert report of Dr. DiGiulio addresses the numerous deficiencies in the County's analysis and why it underestimates the severity of the Project's geologic impacts in further detail. Dr. DiGiulio's analysis highlights the serious risk of CO_2 leaks from the storage reservoirs as well as seismic hazards on wellbores in the Elk Hills oil field, and concludes:

> Given the large number of well penetrations, high pressure during storage, storage primarily as a supercritical fluid, and natural seismicity, leakage through well penetrations is a major concern. . . .
>
> In the absence of a robust investigation of wellbore integrity at the Carbon TerraVault I project, the [Recirculated Draft EIR] should not be approved.[318]

1. The Recirculated Draft EIR must fully account for the significant risk of leaks due to existing wellbores at the Elk Hills oil field.

The Recirculated Draft EIR fails to properly consider any of these issues because it fails at the outset to fully account for the geologic setting at the Elk Hills oil field. When analyzing a project's adverse environmental impacts under CEQA, "[t]he significance of an activity depends on the setting."[319] It is imperative that an EIR accurately and fully describe a project's environmental setting because this description forms the baseline for evaluating its environmental impacts.[320] Indeed, the Recirculated Draft EIR here must demonstrate not only that the CTV I Project's geologic impacts were adequately investigated but that these impacts

[318] DiGiulio Report at 36–37.
[319] *Kings County Farm Bureau*, 221 Cal.App.3d at 718; see also CEQA Guidelines, § 15125.
[320] See CEQA Guidelines, § 15125(a).

were "considered *in the full environmental context.*"[321] It is impossible for the Recirculated Draft EIR to fulfill its informational purpose if it is not adequately describing and considering the existing environment and geologic setting that may be impacted by the Project.

The Elk Hills oil field and its surrounding region have been deeply shaped by oil and gas drilling activity for many decades. Elk Hills is one of the oldest and largest oil fields in the U.S., discovered over 100 years ago, and is characterized by "the presence of a large number of well penetrations."[322] As discussed in the DiGiulio Report, "[l]eakage of CO_2 from wellbores is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2" and the large number of wellbores at Elk Hills therefore "increases the possibility of leakage" which could be "catastrophic."[323]

These risks are exacerbated where, as here, wellbores have not been permanently plugged back to surface, and the Recirculated Draft EIR contains discrepancies in the number of wellbores that require plugging.[324] Some recent estimates indicate that Elk Hills contains nearly 1,400 idle, unplugged wells that have not produced oil or gas for an average 14 years.[325]

Even if properly plugged, Dr. DiGiulio notes that wellbore integrity failure and leaks from plugged wells "is common," with research finding failure rates from 2-75%.[326] Yet the Recirculated Draft EIR found an implausible 0% failure rate in both storage reservoirs, with no wellbores deemed deficient or requiring corrective action.[327]

The Recirculated Draft EIR fails to acknowledge these issues or disclose the inherent and heightened risks of CO_2 storage in a depleted oil field like this one, which renders it lacking in substantial evidence to support its subsequent conclusions about impacts and mitigation.

2. The Recirculated Draft EIR fails to disclose critical details about the Project.

In fact, many of the Recirculated Draft EIR's conclusions about geologic impacts are "impossible to verify" due to missing details.[328] Dr. DiGiulio notes that the document excludes critical information needed to assess wellbore integrity at Elk Hills and the likelihood of leaks

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[321] CEQA Guidelines, § 15125(c) (emphasis added).
[322] Olalde & Menezes, *The Toxic Legal of Old Oil Wells: California's Multibillion-Dollar Problem*, LA Times (Feb. 6, 2020), https://www.latimes.com/projects/california-oil-well-drilling-idle-cleanup/; DiGiulio Report at 4.
[323] DiGiulio Report at 4–5, 7–9 (discussing that the RDEIR appears to have ignored not just the large number of wellbores at the storage areas but also those outside the storage areas at Elk Hills); see also Environmental Integrity Project, *Flaws in EPA's Monitoring and Verification of Carbon Capture Projects* at 5–6.
[324] DiGiulio Report at 15–16; see also RDEIR, Vol. II, App'x A6: Summary of Written Public Comments Received on DEIR (Dec. 2023), Letter from Jeremy Lancaster, State Geologist, Cal. Geological Survey (Mar. 1, 2024) at 850–52 (noting Draft EIR's discrepancy between 7,500+ wells drilled at Elk Hills vs. 354 wellbores at the storage reservoirs).
[325] Olalde & Menezes, *The Toxic Legal of Old Oil Wells: California's Multibillion-Dollar Problem.*
[326] DiGiulio Report at 14.
[327] *Id.* at 16–17.
[328] *Id.* at 16.

from the reservoirs. As one example, the Recirculated Draft EIR repeatedly references appendices with vague or undefined descriptors, and key wellbore schematics are missing.[329] In another example, critical information "relevant to wellbore integrity (e.g., internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc.)" is missing and should be included to facilitate full public participation.[330]

The Recirculated Draft EIR thus violates CEQA's mandate for an EIR to "include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project."[331] Even if pieces of this information are included in EPA's Class VI permit materials or elsewhere, the County is required to include these details with the Recirculated Draft EIR for public review and comment, and to use it to inform its own analysis of impacts and appropriate mitigation for the CTV I Project. The failure of the Recirculated Draft EIR to include this information means the County must revise it with the missing information discussed in the DiGiulio Report included, and provide an adequate public comment period on the recirculated draft.

3. The Recirculated Draft EIR must address how seismic hazards will exacerbate potential geologic impacts.

The Recirculated Draft EIR also does not accurately describe and consider the full environmental context related to seismic activity in the region. Although the Recirculated Draft EIR notes that the County is in the highest seismic hazard zone and discusses the basic seismic history of the region,[332] it inappropriately narrows its analysis of impacts to the bounds of the Elk Hills oil field, which fails to capture potentially significant adverse geologic and safety impacts in the broader region. The analysis otherwise waves away further review of the potential impacts of natural or induced seismicity due to the project because "there are no known major faults within the project area."[333]

By contrast, Dr. DiGiulio classifies the impacts of seismicity on the Project area as "high risk" (vs. the Recirculated Draft EIR's classification of "low to medium" risk) and recommends the County conduct a detailed seismicity evaluation in order to properly determine that seismicity will not impact containment of injected CO_2.[334] The report defines the appropriate "region of concern" as encompassing all seismic events within 200 kilometers from the storage reservoirs, discusses key seismic events in the region's history, and points out that the Recirculated Draft EIR's discussion of seismic events within a smaller 100-kilometer range of the oil field is insufficient for ensuring the Project avoids catastrophic loss of containment.[335] Critically, the seismic risk analysis fails entirely to consider legacy wells or the significant consequences of leaks through these wells.[336] The Recirculated Draft EIR's omission of this

[329] *Id.* at 15–17.
[330] *Id.* at 16.
[331] *Laurel Heights*, *supra*, 47 Cal.3d at 405.
[332] RDEIR, Vol. 1 at 4.7-14, 4.7-5.
[333] RDEIR, Vol. 1 at 4.7-19.
[334] DiGiulio Report at 20, 25–26, 30.
[335] DiGiulio Report at 20–23.
[336] DiGiulio Report at 25.

requisite level of analysis renders the geologic impacts section lacking in substantial evidence to support its conclusions.

In addition, the County's dismissal of the risks of seismicity induced from injection of CO_2 at Elk Hills as "unlikely" is inconsistent with the scientific literature linking fluid injection into deep underground wells with earthquakes.[337] The DiGiulio Report notes "[e]ven in areas of low to moderate natural seismic activity, fluid injection may induce earthquakes in excess of [magnitude] 4."[338] The report discusses numerous real-world examples of injection-induced seismicity that the Recirculated Draft EIR fails to disclose or address when considering the impacts of the CTV I Project, including in particular incidents of CO_2 injection inducing seismic events.[339]

Dr. DiGiulio further explains that "[f]or induced seismicity, the primary concern here is pressure transmission below the Monterey Formation, not above it. In the Class VI regulations, the primary concern is leakage through faults in the confining layer, not transmission of pressure and induced seismicity below the storage formation. Hence, neither EPA regulations nor the [Recirculated Draft EIR] adequately consider induced seismicity."[340] Thus, the County cannot outsource its obligations to properly analyze and mitigate the potential impacts of induced seismicity by ceding those obligations to EPA, a tactic it deploys throughout the geologic impacts section.[341]

Given the risks of natural and induced seismicity and the fact that Kern County and the region surrounding the Elk Hills oil field is already one of the most seismically active in the state—the Central Valley is considered a "hot spot" where oil and gas wells and earthquakes are clustered in space[342]—the Recirculated Draft EIR cannot dismiss potential impacts. Indeed, Dr. DiGiulio notes "[s]eismicity may be induced tens of kilometers away from large-scale injection" which further expands the impact area the County should consider for the Project well beyond the Elk Hills oil field.[343]

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[337] RDEIR, Vol. 1 at 4.7-19; see, e.g., Goebel, T.H.W. et al., *Wastewater Disposal and Earthquake Swarm Activity at the Southern End of the Central Valley, California*, Geophys. Res. Lett., 43 (2016), 1092–99 (hydrogeological modeling reveals wastewater disposal likely contributed to seismicity via localized pressure increase along a seismically active fault, with results suggesting induced seismicity may remain undetected in California without detailed analysis of local geologic setting, seismicity, and fluid diffusion, and proximity of high-rate injectors and large active faults can cause noticeable earthquakes under certain geologic conditions).

[338] DiGiulio Report at 31.

[339] DiGiulio Report at 30–33.

[340] DiGiulio Report at 33.

[341] See Environmental Integrity Project, *Flaws in EPA's Monitoring and Verification of Carbon Capture Projects.*

[342] Kang, M. et al., *Potential Increase in Oil and Gas Well Leakage Due to Earthquakes*, Environ. Res. Commun. (2019), 1: 121004 at 3, https://doi.org/10.1088/2515-7620/ab576e.

[343] DiGiulio Report at 31; see also Kuchment, *Drilling for Earthquakes*, Scientific American (2016), 315, 1, 46–53, https://www.scientificamerican.com/article/drilling-for-earthquakes/ ("Evidence suggests that earthquake risks can spread for miles beyond the original disposal sites and can persist for a decade or more after drilling stops.").

Potential impacts here could include damage to project infrastructure like pipelines, compressors, injection wells, or other wells in the oil field, damage to other structures in the region like roads and buildings, and dangerous CO_2 leaks to air and groundwater that harm the environment and health of nearby communities.[344] Even ground shaking from small- to moderate-sized earthquakes is consequential for a CO_2 repository and capable of creating leakage pathways to the surface.[345] The omission of this information violates CEQA's mandate that the data in an EIR "must be presented in a manner calculated to adequately inform the public and decision makers, who may not be previously familiar with the details of the project," and to give the readers "a better road map to the information it intends to convey."[346]

Overall, the County fails to provide substantial evidence to support the assumptions and conclusions in the geologic impacts section.

4. The Recirculated Draft EIR fails to adequately address cumulative geologic impacts.

The Recirculated Draft EIR's failures described above taint its cumulative impact analysis and render it inadequate under CEQA. While it acknowledges the impacts of cumulative induced seismic activity from the CTV I Project are significant and unavoidable, it otherwise waves away all other geologic impacts and fails to conduct further analysis on the nature and magnitude of the significant risks "due to the uncertainty of the implementation of multiple [CCS] projects and the ability to simultaneously cease injection during a[] [seismic] event."[347] The Recirculated Draft EIR's bare conclusion violates CEQA.[348]

As discussed throughout these comments, the Recirculated Draft EIR must also address "probable future projects."[349] This includes the numerous other CO_2 sources being prepared for CTV I as well as further industrial development that is expected in the region in connection with the Project.

5. The Recirculated Draft EIR fails to adopt all feasible mitigation to address geologic risks.

The Recirculated Draft EIR sets forth mitigation measures to address the geologic impacts of the CTV I Project that are wholly inadequate under CEQA. The DiGiulio Report

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[344] See, e.g., Millman, *California Earthquakes Caused $200 Million in Damage, Report Says*, Wall Street Journal (July 24, 2019), https://www.wsj.com/articles/california-earthquakes-caused-200-million-in-damage-report-says-11564006544 (pair of recent 6.4 and 7.1 magnitude earthquakes in Kern County caused about $200 million in property damage alone, not including damage to infrastructure such as roads or to a nearby naval base); Natural Resources Defense Council (NRDC), *Drilling in California: Who's at Risk?* (2014) at 9, https://www.nrdc.org/sites/default/files/california-fracking-risks-report.pdf; DiGiulio Report at 24.

[345] Zoback, M. & Gorelick, S., *Earthquake Triggering and Large-Scale Geologic Storage of Carbon Dioxide*, 109 PNAS 10164 (2012) at 10165–66, https://doi.org/10.1073/pnas.1202473109.

[346] *Vineyard Area Citizens*, *supra*, 40 Cal. 4th at 443.

[347] RDEIR, Vol. 1 at 4.7-26 to 4.7-27.

[348] *Sierra Club*, *supra*, 6 Cal.5th at 519.

[349] Pub. Resources Code, § 21083(b)(2).

details numerous deficiencies in the County's mitigation measures and why they must be addressed.

The Recirculated Draft EIR acknowledges that earthquakes may disturb surface and subsurface facilities like wellbores at the Project site and could result in loss, injury, or death.[350] It also acknowledges that the site may be subject to strong ground shaking that could cause structural damage and other Project components that could injure people.[351] Thus, the County must adopt all feasible mitigation.

MM 4.7-1 requires CRC to prepare a comprehensive seismic activity monitoring plan that includes connection to the Statewide seismic monitoring program of the California Seismic Network and compliance with state requirements, including "[a]ppropriate subsurface monitoring to ensure geologic sequestration of injected carbon dioxide; [i]dentification of hazards and conditions that may require the suspension of carbon dioxide injections; notification protocols for all applicable agencies and emergency procedures."[352]

The elements of MM 4.7-1 are inadequate and do not represent all feasible mitigation for the impacts of earthquakes and ground shaking. The DiGiulio Report points out that, while a seismic monitoring plan would be able to detect an earthquake, it does not reduce damage to surface and subsurface facilities, and thus the impacts should be considered significant and unavoidable, rather than less than significant as the Recirculated Draft EIR concludes.[353]

The DiGiulio Report provides numerous recommendations for seismic monitoring network design that are missing and should be included in MM 4.7-1 to comply with CEQA's requirement to adopt all feasible mitigation.[354] As the Report notes, "monitoring of natural seismicity is not mitigation."[355]

In addition, MM 4.7-1 is riddled with vague and indefinite terms. Under CEQA, a mitigation measure must include criteria or performance standards against which the mitigation's actual implementation can be measured.[356] MM 4.7-1, however, is a laundry list of vague actions such as "appropriate" subsurface monitoring, "[i]dentification of hazards and conditions," and "notification protocols for all applicable agencies and emergency procedures."[357] The Recirculated Draft EIR must be revised to include measurable and enforceable mitigation measures to address the Project's impacts. Open-ended and therefore potentially meaningless terms in a mitigation measure that will be developed at an unspecified time in the future also violate CEQA's requirements for deferred mitigation.

MM 4.7-1 is also effectively unenforceable because the Recirculated Draft EIR does not contain permit conditions, agreements, or other legally binding instruments that ensure the

[350] RDEIR, Vol. 1 at 4.7-17.
[351] RDEIR, Vol. 1 at 4.7-19.
[352] RDEIR, Vol. 1 at 4.7-18.
[353] DiGiulio Report at 29.
[354] DiGiulio Report at 33–36.
[355] DiGiulio Report at 29.
[356] *San Joaquin Raptor Rescue Ctr.*, *supra*, 149 Cal.App.4th at 670.
[357] RDEIR, Vol. 1 at 4.7-18.

seismic monitoring plan will be prepared and implemented, and who will enforce it.[358] The Measure must specify that no construction or grading permits shall be issued, and no activities expected to cause earthquakes or ground shaking may otherwise commence, unless and until the County, EPA Region 9, CARB, and California Seismic Network all approve the seismic monitoring plan for the CTV I Project. The County must specify such a limitation because "mitigation measures must be in place" when a "project reaches the point where activity will have a significant adverse effect on the environment."[359]

The DiGiulio Report points out that the Recirculated Draft EIR's claim that mitigation of strong ground shaking "is typically provided by designing structures in accordance with the latest edition of the California Building Code" is flawed.[360] Because the Building Code does not address wellbore integrity, compliance would not mitigate potential impacts for this Project, thus the impacts should be considered significant and unavoidable, not less than significant.[361]

It is important to note that merely requiring compliance with agency regulations or other existing requirements like the California Building Code does not conclusively indicate that the Project would not have a significant and adverse impact. Those legal requirements may not be strong enough to protect against environmental impacts. In *Kings County Farm Bureau v. City of Hanford*, for example, the court found that the fact that EPA and the local air pollution control district had issued the necessary air emission permits for the construction of a coal fired cogeneration plan did not nullify the CEQA requirement that the lead agency analyze the significant air quality impacts of the entire project.[362] Similarly here, the Recirculated Draft EIR cannot rely on the Building Code to conclude that impacts would not be significant based on those requirements, without at least describing what those requirements are and how they would reduce the Project's geologic impacts to less than significant.

MM 4.7-3 is also inadequate and does not represent all feasible mitigation for the impacts of unstable soil or land that could result in landslides, subsidence, liquefaction, or collapse. The Measure states that CRC "shall implement all requirements of a site-specific geotechnical report" with no further detail or direction.[363] This language is vague and indefinite, and defers development of the geotechnical report until an unspecified time in the future. The Recirculated Draft EIR must be revised to include measurable and enforceable terms for the report to address the Project's impacts. Moreover, without any permit conditions or other legally binding instruments to ensure the report will be prepared and implemented, this measure is entirely unenforceable. The Recirculated Draft EIR must specify that no permits shall be issued and no activities expected to cause landslides, subsidence, liquefaction, or collapse may begin until the County and other relevant agencies approve the report.

The flaws in the Recirculated Draft EIR's analysis of geologic risks also impacts its development of mitigation measures to address cumulative impacts. After acknowledging

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[358] Pub. Resources Code, § 21081.6(b); CEQA Guidelines, § 15126.4(a)(2).
[359] *King and Gardiner Farms, supra,* 45 Cal.App.5th at 860, quoting *POET*, *supra,* 218 Cal.App.4th at 738.
[360] RDEIR, Vol. 1 at 4.7-19.
[361] DiGiulio Report at 29.
[362] *Kings County Farm Bureau*, *supra*, 221 Cal.App.3d at 716.
[363] RDEIR, Vol. 1 at 4.7-22.

significant and unavoidable cumulative impacts, the document makes no attempt to adopt feasible mitigation, claiming "there are no other feasible and reasonable mitigations available" other than the deficient measures discussed above.[364] This failure violates CEQA, particularly given the analysis and recommendations in the DiGiulio Report.

In addition to addressing the deficiencies in the Recirculated Draft EIR's current mitigation measures for geologic impacts and strengthening its seismic monitoring and mitigation plan measures, the DiGiulio Report recommends numerous additional feasible mitigation measures that the County should adopt to address the CTV I Project's serious impacts. One example that would protect nearby communities—and reflect measures already considered for other impacts in the Recirculated Draft EIR—is to "determine safe distance(s) for injection wells, wellbores, and pipelines from human receptors and adopt setback(s) that prohibit development at unsafe distance(s)."[365]

E. The Recirculated Draft EIR's Analysis and Mitigation of CO_2 Pipeline Safety Hazards is Inadequate.

The Recirculated Draft EIR fails to adequately disclose, analyze, and mitigate the serious carbon dioxide pipeline safety hazards of the CTV I Project. The attached Kuprewicz Report addresses the numerous deficiencies in the County's analysis in further detail and why they obscure the severity of the Project's pipeline safety impacts. The issues raised in the report highlight why the Recirculated Draft EIR is defective as an informational document.

1. The Recirculated Draft EIR fails to provide critically important pipeline information.

As the Kuprewicz Report concludes, "[i]mportant pipeline information is missing in the [Recirculated Draft EIR] that will not permit decisionmakers to make an informed decision about this Project."[366] The Report offers a list of key examples of the Recirculated Draft EIR's "major shortcomings" and failure to disclose critical details about the Project.[367]

The missing details about the nature of the CTV I Project's pipeline construction and operations prevent understanding of the applicable regulations and safety jurisdiction of relevant agencies, and thus a complete analysis and appropriate mitigation. As one example, the Recirculated Draft EIR includes a laundry list of potential sources for the Project "without identifying how such sources will be transported to the Elk Hill facilities—a critical omission."[368]

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[364] RDEIR, Vol. 1 at 4.7-27.
[365] DiGiulio Report at 5.
[366] Kuprewicz Report, Attachment A at 2. The Kuprewicz Report consists of a brief cover note addressing the Recirculated Draft EIR, and Attachment A, which is Richard Kuprewicz's assessment of the original Draft EIR. The cover note states that the Recirculated Draft EIR did not meaningfully address his assessment of the original Draft EIR, which still fully applies, and that the pipeline safety analysis and relevant mitigation measures remain inadequate.
[367] Kuprewicz Report, Attachment A at 2–5.
[368] Kuprewicz Report at 1.

The Recirculated Draft EIR also contains inaccurate and misleading details that obscure a full understanding of potential pipeline safety impacts. For example, the Kuprewicz Report discusses the Recirculated Draft EIR's attempts to minimize the extent of impacts from the Satartia, MS pipeline rupture.[369] Relatedly, the Recirculated Draft EIR also completely fails to address the possibility of a CO_2 injection well blowout, which "can release many thousands of tons from essentially an infinite supple of CO_2 in the reservoir, easily surpassing pipeline rupture releases."[370]

The deficiencies in the Recirculated Draft EIR are particularly consequential given the history of explosions and disasters that have harmed people in pipeline-related incidents,[371] and the ongoing harms faced by communities in the Elk Hills region due to oil and gas activity. In fact, as recently as February 2024, a pipeline burst in Bakersfield, releasing barrels of oil on a public street next to Buena Vista Elementary School.[372] Between January 1, 2010, and January 19, 2023, a total of 8,140 pipeline incidents were reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA), an average of 1.7 incidents per day. Hazardous liquid pipelines (which encompass CO_2 pipelines) accounted for more than half of these incidents.[373] The DiGiulio Report also discusses at length examples of large-scale CO_2 releases and their impacts on neighboring communities.[374]

Notably, a prior similar carbon capture proposal in the Elk Hills oil field that would have compressed CO_2 from a hydrogen plant and transported it to the field via pipeline to 25 injection wells for enhanced oil recovery found serious safety risks.[375] Specifically, the project risk assessment for its approximately 3 mile pipeline—about a quarter of the length of the CTV I Project's planned pipelines—determined that a large amount of CO_2 could be released into the atmosphere if it failed.[376] Studies find that exposure to large amounts of CO_2 could lead to harmful impacts like irritation, chronic or irreversible tissue damage, or narcosis, and to irreversible health effects, impairing, or even death for close exposure to the release.[377] None of these issues are addressed in the Recirculated Draft EIR, rendering it lacking in substantial evidence to support its conclusions.

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[369] Kuprewicz Report, Attachment A at 6.
[370] Kuprewicz Report, Attachment A at 6–7.
[371] See, e.g., Zegart, Dan, *The Gassing of Satartia*.
[372] LaVigne, *Pipe Burst Spills Oil in Front of Buena Vista Elementary School*, KERO-TV (Feb. 8, 2024), https://www.turnto23.com/news/in-your-neighborhood/bakersfield/pipe-burst-spills-oil-in-front-of-buena-vista-elementary-school.
[373] FracTracker Alliance, *2022 Pipeline Incidents Update: Is Pipeline Safety Achievable?* (Feb. 1, 2023), https://www.fractracker.org/2023/02/2022-pipeline-incidents-update-is-pipeline-safety-achievable/.
[374] DiGiulio Report at 4–5.
[375] Submitted by Occidental of Elk Hills, Inc. to Cal. Dept. of Conservation, *Proposed Enhanced Oil Recovery Project (Phase 1), Underground Injection of Carbon Dioxide Gas, Stevens Reservoirs – T30, 31S, R23, 24E, Sections 33S, 34S, 35S, 2G, 3G, & 4G, Engineering Study, Geologic Study, and Injection Plan* (Oct. 2, 20212) at 1, 6.
[376] Stantec, *Hydrogen Energy Center Application for Certification Amendment –Attachment D: Hazards Assessment of CO_2 Supply Line* (Apr. 12, 2011) at 7.
[377] *Id.* at 6–7.

The Recirculated Draft EIR's failures are particularly stark given the evidence that most CCS pipelines fall largely within environmental justice communities, like those surrounding Elk Hills, that live in close proximity to industrial pollution.[378]

Given its serious deficiencies, the Recirculated Draft EIR's dismissal of all pipeline-related impacts, including cumulative impacts, as less than significant is not supported by substantial evidence.

2. The Recirculated Draft EIR fails to adopt all feasible mitigation to address pipeline safety hazards.

Because of the missing and inaccurate information regarding CO_2 pipeline safety issues, it is impossible for the Recirculated Draft EIR to satisfy CEQA's requirement to adopt all feasible mitigation measures for these impacts. The proposed measures are also ineffective, unenforceable, and vague, and illegally defer mitigation.

For example, MM 4.9-4 requires a construction permit site plan for all CO_2 pipelines, which will be reviewed and approved by the County and California State Fire Marshall (OSFM), noting that PHMSA has delegated CO_2 pipeline oversight to OSFM.[379] In addition to this Measure being vague and improperly deferring the plan to an unspecified future date, it is unclear whether OSFM actually has proper jurisdiction over the CTV I Project's CO_2 pipelines. As discussed in the Kuprewicz Report, the Recirculated Draft EIR's failure to provide CO_2 purity information and clearly distinguish between facility and injection pipelines obscures whether either agency has jurisdiction and responsibility for the Project.[380] The report also highlights that federal pipeline safety regulations are seriously inadequate, thus the County cannot rely on compliance alone to avoid fulfilling its own separate obligations under CEQA to properly assess and mitigate impacts.[381]

As another example of the Recirculated Draft EIR's deficient mitigation measures, MM 4.9-10 only requires compliance with EPA's Class VI permit before injection can begin.[382] As discussed throughout these comments, merely requiring compliance with existing regulations or other requirements like the Class VI requirements without further review or analysis does not conclusively indicate that the Project would not have significant and adverse impacts.

Concerningly, MM 4.11-7 seems to indicate that offsite sources can inject at CTV I via CO_2 pipelines permitted by the California Public Utilities Commission (PUC) for common carrier companies—without explaining the nature of these offsite sources or any relevant details about the connecting pipelines or potential common carrier companies.[383] This measure is therefore vague, indefinite, and does not represent all feasible mitigation. Moreover, given the current moratorium on intrastate pipelines in the state due to the requirements of Senate Bill

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[378] Rota, M., *Carbon Dioxide Waste Capture and Injection: A False Solution for Louisiana and the World* (2023), https://healthygulf.org/carbon-waste-injection-false-solution-for-louisiana/.
[379] RDEIR, Vol. 1 at 4.9-58.
[380] Kuprewicz Report, Attachment A at 2–3.
[381] Kuprewicz Report, Attachment A at 5.
[382] RDEIR, Vol. 1 at 4.9-61.
[383] RDEIR, Vol. 1 at 4.11-54.

905,[384] the relevance of common carrier CO_2 pipelines is vague and "should be raising serious concerns about possible efforts to move CO_2 in converted existing pipelines as a gas to circumvent the moratorium."[385] Given it appears CRC has recently applied to the PUC for a certificate to operate as a gas utility in the state, the Recirculated Draft EIR's omission of these details, or CRC or CTV's larger plans for pipeline transport, is glaring and improper under CEQA.[386]

These highlighted examples are just a sample and illustrate the overall failures of the Recirculated Draft EIR to analyze and adopt all feasible CO_2 pipeline safety mitigations for the CTV I Project. The Kuprewicz Report recommends additional feasible mitigation measures that the County should adopt to address CO_2 pipeline impacts, including, as noted elsewhere, that the County should adopt setbacks from the pipelines.[387]

F. The Recirculated Draft EIR's Analysis and Mitigation of Water Supply Impacts is Inadequate.

An accurate analysis of the CTV I Project's impact on the local water supply is crucial because water is scarce in Kern County and groundwater pumping has occurred at unsustainable levels for decades, resulting in overdraft conditions region-wide, county-wide, and within the Project Area. Unfortunately, the Recirculated Draft EIR fails to adequately disclose and analyze water supply impacts and correspondingly fails to adopt all feasible mitigation.

As an initial matter, it is worth noting that the Recirculated Draft EIR is confusing because the header for the section on Utilities and Service Systems—one of the several sections that address water supply issues—is mislabeled as "4.17 Utilities and Service Systems."[388] The section on Utilities and Service Systems is actually section 4.19. The erroneous header should be corrected because it is confusing to the reader and complicates navigation of the document.

1. The Recirculated Draft EIR's description of the environmental and regulatory setting for water supply is inadequate.

The Recirculated Draft EIR is misleading and fails as an informational document because, remarkably, it fails to acknowledge the most basic fact about water supply in Kern County: there is "no surplus water available" in the County to meet domestic and/or irrigation demands, meaning that any use of municipal and industrial (M&I) quality water by the proposed

[384] Senate Bill No. 905 (2021–2022 Reg. Sess.), approved by Governor, Sept. 16, 2022.
[385] Kuprewicz Report at 1.
[386] Cal. P.U.C., *Application of California Resources Production Corporation for a Certificate of Public Convenience and Necessity to Operate as a Gas Corporation in the State of California* (July 10, 2023).
[387] Kuprewicz Report, Attachment A at 4–5; DiGiulio Report at 5; see also Hillebrand, M. et al., *Toxicological Risk Assessment in CO_2 Capture and Storage Technology*, International Journal of Greenhouse Gas Control 55 (2016) 118–43 (concentrations of CO_2 releases from pipelines are function of distance, thus safety distances have to be calculated wherein no hazardous concentrations are reached, varying between <1 m and 7.2 kilometers).
[388] See, e.g., RDEIR, Vol. 1 at 4.19-2 (with "4.17 Utilities and Service Systems" in the header).

CTV I Project necessarily "reduces potential supplies for other purposes and users."[389] The Recirculated Draft EIR should disclose this reality upfront to the public and decisionmakers.

The details that the Recirculated Draft EIR does provide downplay the Project's water supply impacts and are inadequate. For example, in describing the relevant "Environmental Setting" for the CTV I Project's impact on water supply, the document merely notes that "[t]he project site is located within the Tulare Lake Basin," which "is ranked as 'high priority' in a statewide ranking of groundwater importance."[390] The Recirculated Draft EIR also notes "[t]he Kern County Subbasin ('Subbasin') is the specific groundwater subbasin in which the project resides."[391]

To meaningfully inform readers, the Recirculated Draft EIR must explain the significance of the Tulare Lake Basin's designation of "high priority" and offer more details on conditions in the Tulare Lake Basin generally and the Kern County Subbasin specifically.

The Tulare Basin is designated as "high priority" both because the region is heavily reliant on groundwater and because groundwater supplies are in a condition of "critical overdraft."[392] Similarly, the Kern County Subbasin has been identified as "high priority," reflecting that the area is "critically overdrafted" and suffers from related problems including "land subsidence and groundwater quality degradation."[393] Persistent overdraft of groundwater also "dries up wells."[394]

Although the Recirculated Draft EIR acknowledges that the Kern County Subbasin, "as a whole, has an overdraft of 324,326 acre-feet per year over the baseline conditions,"[395] nowhere is the significance of this fact explained.

The Recirculated Draft EIR is similarly misleading and incomplete in its description of the regulatory setting for water supply. The document includes a general discussion of the Sustainable Groundwater Management Act (SGMA) and how it is being implement in the Project Area.[396] As part of this discussion, the Recirculated Draft EIR notes the status of six groundwater sustainability plans (GSPs) that have been prepared for the San Joaquin Valley Kern County Subbasin.[397] However, nowhere does the Recirculated Draft EIR explain that

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[389] Kern County Planning & Natural Resources Dept., *Draft Supplemental Recirculated Environmental Impact Report for Revisions to Title 19-Kern County Zoning Ordinance, Supplemental Water Supply Baseline Technical Report* (July 2020) at 4, 58.
[390] RDEIR, Vol. 1 at 4.10-1.
[391] RDEIR, Vol. 1 at 4.10-2.
[392] RDEIR, Vol 2., Water Supply Assessment for the Carbon Terravault 1 Project at 2–3.
[393] RDEIR, Vol. 2, West Kern Water District, Urban Water Management Plan 2020 Update (June 2021) at 34.
[394] Rachel Becker, *San Joaquin Valley growers may face probation for failing to protect groundwater*, Cal Matters (Oct. 12, 2023), https://calmatters.org/environment/2023/10/san-joaquin-valley-groundwater/.
[395] RDEIR, Vol. 1 at 4.10-35, 4.19-2, 4.19-21.
[396] RDEIR, Vol. 1 at 4.10-15 to 4.10-17, 4.19-7 to 4.19-8.
[397] RDEIR, Vol. 1 at 4.10-16, 4.19-8; see also *id*. at 4.19-13 to 4.19-14.

SGMA applies to Kern County and the Project Area because the Act was designed to address chronic groundwater overdraft and its negative consequences.

Further, the Recirculated Draft EIR neglects to address whether or how the six GSPs will affect the available water supplies in the Kern County Subbasin generally or for the Project specifically. Although the Recirculated Draft EIR indicates that state authorities have determined that the six GSPs are deficient in some respects, the Recirculated Draft EIR also confirms that, under SGMA, local Groundwater Sustainability Authorities are still "required to begin implementation of the plans . . . while working to amend the plans and address the deficiencies."[398] The Recirculated Draft EIR should address the expected consequences of the GSPs—if any—on the proposed CTV I Project and its planned operations and water use.

2. The Recirculated Draft EIR's analysis of the Project's impact on water supply is contradictory, inaccurate, and misleading.

The Recirculated Draft EIR fails as an informational document because it does not clearly explain the source or amount of water that will be used by the Project.

First, the Recirculated Draft EIR makes conflicting statements about the source of water to be used by the CTV I Project. In section 4.10, the Recirculated Draft EIR states: "[t]he proposed project would use water during construction and for operation of the project. Water for the project would be supplied by the WKWD from existing water allocations for Elk Hills and CRC."[399] Further, according to section 4.10, "all water would be trucked to the site from the WKWD." [400]

The foregoing description of the source of the Project's water supply is contradicted by text in section 4.19 which states that—for Project operations—"[w]ater to operate the carbon capture and storage (CCS) facilities is proposed to be sourced from produced water from existing oil and gas operations within Elk Hills."[401]

Second, no matter the source, the Recirculated Draft EIR inaccurately and misleadingly describes the Project's water supply demand. Table 4.19-2 describes the Project's water demand as follows:

[398] RDEIR, Vol. 1 at 4.10-17, 4.19-8, 4.19-14.
[399] RDEIR, Vol. 1, at 4.10-34.
[400] RDEIR, Vol. 1 at 4.10-35.
[401] RDEIR, Vol. 1 at 4.19-19.

Table 4.19-2: Water Supply Availability

	Allotment (acre-feet per year)	Project Demand	Usage of Water Allotment
Elk Hills	3,000		
CRC	2,200		
Construction (18 months)		75 acre-feet	1.4%
Operation (per year)		19.49 acre-feet	0.37%
Total	**5,200**	**94.49 acre-feet**	**1.77%**

Key:
CRC = California Resources Corporation

This table is clearly wrong. The table incorrectly combines a one-time water demand for construction (75 acre-feet) with an annual operational demand (19.49 per year) and concludes that the "Total" Project demand is 94.49 acre-feet. But this is not an accurate total. Just the first phase of the Project is expected to last "26 years,"[402] meaning that operational water demand will amount to at least 506.74 acre-feet (19.49 acre-feet annually x 26 years). The Recirculated Draft EIR must be revised to eliminate Table 4.19-2, which is inaccurate and misleading. Further, the document must disclose how much water the Project will use over its full operational lifetime.

3. The Recirculated Draft EIR's finding that the Project will not substantially reduce groundwater supplies is not supported by substantial evidence.

The Recirculated Draft EIR offers several reasons to support its conclusion that the CTV I Project will not substantially decrease groundwater supplies, all of which are erroneous.

First, the Recirculated Draft EIR states: "Project operation would not rely on locally sourced groundwater wells, as all water would be trucked to the site from the WKWD [West Kern Water District]."[403] But WKWD supplies the water it provides from "groundwater within the Kern County subbasin,"[404] meaning the Project's water use will still impose a burden on local groundwater supplies.

Second, the Recirculated Draft EIR asserts that, even accounting for pre-Project water use at the Project site, water use is expected to remain below the WKWD's future water budget for CRC and Elk Hills, which affords 5,200 acre-feet per year.[405] As an initial matter, it is unclear if the future water budget adopted for the Project site by WKWD in 2020 remains valid, given that the Kern Groundwater Authority (KGA) is currently responsible for an annual

[402] RDEIR, Vol. 1 at 1-6, 2-1, 3-2, 3-12.
[403] RDEIR, Vol. 1 at 4.10-35.
[404] RDEIR, Vol. 1 at 3-36; accord 4.10-40, 4.10-43, 4.19-2 (stating "WKWD primarily pumps groundwater").
[405] RDEIR, Vol. 1 at 4.19-20 to 4.19-21.

overdraft of 239,346 acre-feet per year,[406] and state authorities have disapproved KGA's proposed Groundwater Sustainability Plan for the area.[407]

In any event, the fact that the WKWD may have budgeted for operations at the site does not mean that the Project's expected water use will not have a significant impact. As noted above, there is no surplus water in Kern County, groundwater in the Kern Subbasin is suffering from critical overdraft, and the water to be used by the Project will all be sourced from groundwater. Whether water use at the site was anticipated or not, the Project will still be using substantial quantities of groundwater.

Third, the Recirculated Draft EIR avers that, "[s]hould the project require water supplies in excess of the allotment from the District, impacts to water supplies would be considered potentially significant. In order to address this, MM 4.19-1 would be implemented, ensuring that any groundwater or reclaimed water used is accounted for and regulated."[408]

The Recirculated Draft EIR's adoption of MM 4.19-1 does not support a finding that the Project's groundwater use will be mitigated to a level of insignificance. That is because MM 4.19-1 in no way limits or mitigates the Project's water use. Rather, the Measure just specifies that the Project Owner/operator shall "provide information on any groundwater . . . that will be used," and County officials, in turn, "shall compile the water use information in a report" to be posted online annually.[409] This Measure does not reduce or limit water use; it merely requires that "that any groundwater . . . used is accounted for."[410]

4. The Recirculated Draft EIR fails to adopt all feasible mitigation for the Project's cumulative impacts on water supply.

Putting aside the Recirculated Draft EIR's unsupported finding that the Project will not have a significant direct impact on groundwater supplies, the document does acknowledge that "the cumulative impacts of any use of groundwater in the area are considered significant."[411] Consequently, the County must adopt all feasible mitigation to address this cumulative impact.

The Recirculated Draft EIR identifies several mitigation measures that will purportedly address this significant cumulative impact on water supply: MMs 4.9-1, 4.10-1, 4.10-2, 4.10-3, 4.10-4, 4.10-5, and 4.19-1.[412] But none of these measures will actually reduce the Project's impact on groundwater supplies:

[406] See, e.g., RDEIR, Vol. 1 at 4.19-21
[407] See, e.g., RDEIR, Vol. 1 at 4.19-13 to 4.19-14.
[408] RDEIR, Vol. 1 at 4.10-35, 4.19-21.
[409] RDEIR, Vol. 1 at 1-65, 4.19-21 to 4.19-22.
[410] RDEIR, Vol. 1 at 4.19-27.
[411] RDEIR, Vol. 1 at 1-14 to 1-15, 4.10-43, 4.19-28, 5-5 to 5-6, 6-7.
[412] RDEIR, Vol. 1 at 4.10-43 to 4.10-44.

- MM 4.9-1 provides worker training on the handling of hazardous substance,[413] but the Project site is not a source of groundwater for M&I uses, which is supplied from elsewhere by WKWD.[414]
- MMs 4.10-1 through 4.10-5 all address onsite operations (i.e., stormwater measures and management of drilling muds, drilling fluids, and produced water)[415] but, again, the Project site is not a source of groundwater for M&I uses, which is supplied from elsewhere by WKWD.
- MM 4.19-1, as discussed above, merely requires reporting on groundwater use, and does not limit its use in any way.

Consistent with CEQA's requirement to adopt all feasible mitigation, the County should require the following feasible measures to mitigate the Project's impacts on local groundwater supplies:

- The County should identify specific purposes for which the Project may use M&I quality water—limited to those purposes for which such high-quality, freshwater is truly necessary—and direct that all other water uses in the Project area shall be met by recycling oil field-produced water. The Recirculated Draft EIR indicates that such recycling and reuse of oil filed-produced water already occurs at the site.[416] The County should make this voluntary practice mandatory.
- The County should set a cap on the CTV I Project's water use. According to the Recirculated Draft EIR, if construction activities (75 acre-feet) and operational activities (19.49 acre-feet) were to occur in the same year, the Project's water demand would total 94.49 acre-feet annually.[417] The Project should be held accountable for its estimated water needs and limited to an annual cap of 95 acre-feet per year or less for its CCS operations. In setting the cap, the County should subtract any use(s) included in the Project's estimated water demand that could be met by recycling oil field-produced water.
- The County should levy and collect an annual "fair-share" fee from the Owner/operator to be paid to the KGA to account for the Project's contribution to cumulative impacts on local groundwater supplies that KGA must mitigate pursuant to SGMA.

[413] RDEIR, Vol. 1 at 1-46, 4.9-56.
[414] RDEIR, Vol. 1 at 4.10-7 to 4.10-8 (noting "there is no appreciable quantity of groundwater in the project area" and "any groundwater encountered in this area is generally unusable"); 4.19-2 (stating WKWD's "[w]ater supply is obtained within the District from wells located in the northeast corner of the District in the underflow area of the Kern River Basin and from an area north and adjacent to the State of California's Tule Elk Reserve").
[415] RDEIR, Vol. 1 at 1-53 to 1-56, 4.10-29 to 4.10-33.
[416] RDEIR, Vol. 1 at 4.10-8.
[417] RDEIR, Vol. 1 at 4.19-21.

5. The Recirculated Draft EIR inadequately analyzes and mitigates disposal of oil field-produced water.

The Recirculated Draft EIR notes that "[a] significant percentage of the oil field-produced water in the project area is either recycled into the same geologic zones from which it was produced or is sequestered in deeper zones that are isolated from sources of drinking water."[418] Water that is not recycled or sequestered underground requires disposal. According to the Recirculated Draft EIR, produced water "may also be transported, via truck or pipeline to existing wastewater treatment facilities permitted to receive production water for disposal" or "stored in surface impoundments where it percolates into groundwater and/or evaporates."[419]

The Recirculated Draft EIR is inadequate as an informational document because it does not specify what percentage of the oil field-produced water is currently (in the oil field) or will be (for the Project) recycled and reinjected onsite as opposed to disposed of in some other way. Instead, the Recirculated Draft EIR merely surmises that "very little water is disposed of . . . because purchasing fresh water is more expensive than recycling water."[420] The document can and should be more specific to inform the public and decisionmakers; it should detail current water disposal volume(s) and practice(s) at the Project site and how these are expected to change, if at all, with the construction and operations of the proposed CCS facility.

It is important that the Recirculated Draft EIR accurately address the fate of oil field-produced water because it has consequences for the CTV I Project's impacts:

- As the Recirculated Draft EIR suggests, a high rate of recycling would lessen the degree to which the Project will compete with other users for scarce municipal and industrial-quality water.[421]
- Conversely, if transportation of the oil field-produced water by truck or pipeline is required for disposal, related environmental impacts must be evaluated and mitigated. For example, the Recirculated Draft EIR notes that truck traffic impacts air quality.[422]
- Surface disposal of oil field-produced water in ponds also threatens impacts that should be disclosed if the practice will occur. "Because it was commingled with hydrocarbons in the formation," produced water "typically contains chemicals associated with the formations, such as salts, oils and greases, inorganic and organic chemicals, and naturally occurring radioactive material, that exceed state and federal standards for drinking water."[423] Disposal in surface impoundments can therefore increase air pollution as well as contaminate the soil and harm biological resources.

[418] RDEIR, Vol. 1 at 4.10-8.
[419] RDEIR, Vol. 1 at 4.9-7.
[420] RDEIR, Vol. 1 at 4.10-8.
[421] RDEIR, Vol. 1 at 4.10-8.
[422] See, e.g., RDEIR, Vol. 1 at 4.3-63, 4.3-66, 4.3-72.
[423] RDEIR, Vol. 1 at 4.9-7.

Although the Recirculated Draft EIR does not analyze the impact, the document seems to contemplate that surface impoundments will, in fact, be used for disposal of oil field-produced water. More specifically, MM 4.10-5 states: "[t]he Owner/operator shall not discharge produced water into any surface disposal facility unless the facility has received the Waste Discharge Requirements from the Central Valley Regional Water Quality Control Board, or the need for Water Discharge Requirements has been waived by the Central Valley Regional Water Quality Control Board."[424] Likewise, MM 4.1-2 states: "[s]umps and ponds shall be permitted only to the extent authorized by the Central Valley Regional Water Quality Control Board . . . and shall comply with all applicable legal requirements and mitigation measures for . . . percolation or evaporation ponds for produced water."[425]

If the CTV I Project proposes to use such surface impoundments at the Project site, the extent to which they may be used and the impacts of such use must be disclosed. An adequate impact analysis is necessary to inform the development of all feasible mitigation measures and to include meaningful public input on the impacts and proposed mitigation.

G. The Recirculated Draft EIR's Analysis and Mitigation of Biological Resources Impacts is Inadequate.

Protecting biological resources is a fundamental tenet of CEQA. Under Public Resources Code section 21001(c), it is the policy of the state to "[p]revent the elimination of fish or wildlife species due to man's activities, insure that fish and wildlife populations do not drop below self-perpetuating levels, and preserve for future generations representations of all plant and animal communities." EIRs must provide an in-depth analysis of whether a project will: reduce substantially the habitat of a fish or wildlife species; cause a fish or wildlife population to drop below self-sustaining levels; threaten to eliminate a plant or animal community; or reduce substantially the number or restrict the range of an endangered, rare, or threatened species.[426]

In addition to review under CEQA, when a project has the potential to significantly impact a species listed under the federal or California Endangered Species Act, consultation with wildlife agencies and an Incidental Take Permit (ITP) are required.[427]

1. The Recirculated Draft EIR must account for the threatened, endangered, and sensitive animal and plant species in the Central Valley and Elk Hills oil field.

The Elk Hills oil field and surrounding area is known to support high densities of species protected by state and federal law. The California Department of Fish and Wildlife (CDFW) has specifically called out several species known to be supported in the area through prior biological surveys, including the blunt-nosed leopard lizard, giant kangaroo rat, San Joaquin kit fox, Swainson's hawk, San Joaquin antelope squirrel, American badger, short-nosed kangaroo rat,

[424] RDEIR, Vol. 1 at 1-56, 4.10-33.
[425] RDEIR, Vol. 1 at 1-27, 4.1-23.
[426] CEQA Guidelines, § 15065(c)(1).
[427] Cal. Fish & Game Code, § 2081; Endangered Species Act, § 10.

burrowing owl, California glossy snake, and California jewelflower.[428] As CDFW noted in its comment on the original Draft EIR, since 2022, "two species have become candidates for listing under CESA and remain candidates as of the date . . . . [the] Temblor legless lizard and Crotch's bumble bee."[429]

In its comments on the Notice of Preparation, CDFW recommended additional surveys for special status plant species and also noted the potential for San Joaquin pocket mouse.[430] In addition, CDFW shared with the California Geologic Energy Management Division (CalGEM) in 2022 that "there is potentially suitable habitat [in the Elk Hills oil field] within the well pad footprints and/or adjacent to the wells that can serve as refugia, denning, breeding, foraging, and dispersal habitat" for additional species "likely to occur within th[e] oil field," including the Tipton kangaroo rat, tricolored blackbird, Temblor legless lizard, Kern mallow, San Joaquin woolly threads, Buena Vista Lake shrew, LeConte's thrasher, loggerhead shrike, Tulare grasshopper, San Joaquin coachwhip, California glossy snake, coast horned lizard, western pond turtle, western spadefoot, prairie falcon, California horned lark, and Crotch bumble bee.[431] That 2022 letter also notes that several special-status plant species may occur in the oil field, including California Rare Plant Rank species Horn's milk-vetch, heartscale, Lost Hills crownscale, slough thistle, recurved larkspur, Temblor buckwheat, Tejon poppy, alkali-sink goldfields, pale-yellow layia, showy golden madia, California alkali grass, and oil neststraw.[432]

[428] Letter from Bob Stafford, California Department of Fish and Wildlife, to Cindi Hoover, Kern County Planning & Natural Resources Dept. (Apr. 6, 2022), RDEIR, Vol. 2, App'x A.2: Comment Letters at 148 (hereafter "Stafford Letter"); see also RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1067, CDFW Letter: Comment from Julie A. Vance, Cal. Department of Fish & Wildlife, to Keith Alvidrez, Kern County Planning & Natural Resources Dept. (Mar. 1, 2024) (hereafter "CDFW Letter").
[429] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on Draft EIR (December 2023) at 1067–68, CDFW Letter.
[430] Stafford Letter at 159, 162.
[431] Letter from CDFW to CalGEM, Elk Hills Oil Field, Kern County, Special-Status Species Information from CDFW (revised Aug. 12, 2022) at 1.
[432] *Id.* at 6.

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

Common Name	***Scientific Name***	***Federal/State Status***	***CDFW Letter[433]***
	Plants		
California jewelflower	***Caulanthus californicus***	***FE/CE, 1B.1***	**1, 2**
San Joaquin woollythreads	***Monolopia congdonii***	***FE/1B.2***	**2**
Kern mallow	***Eremalche parryi ssp. kernensis***	***FE/1B.2***	**2**
Horn's milk-vetch	*Astragalus hornii var. hornii*	*S/1B.1*	2
heartscale	*Atriplex cordulata var. cordulata*	*S/1B.2*	2
Lost Hills crownscale	*Atriplex coronata var. vallicola*	*S/1B.2*	2
Slough thistle	*Cirsium crassicaule*	*S/1B.1*	2
recurved larkspur	*Delphinium recurvatum*	*S/1B.2*	2
Temblor buckwheat	*Eriogonum temblorense*	*S/1B.2*	2
Tejon poppy	*Eschscholzia lemmonii ssp. kernensis*	*S/1B.1*	2
alkali-sink goldfields	*Lasthenia chrysantha*	*--/1B.1*	2
pale-yellow layia	*Layia heterotricha*	*S/1B.1*	2
showy golden madia	*Madia radiata*	*S/1B.1*	2
California alkali grass	*Puccinellia simplex*	*S/1B.2*	2
oil neststraw	*Stylocline citroleum*	*S/1B.1*	2
	Insects		
Crotch bumble bee	*Bombus crotchii*	*--/WL*	2
	Amphibians		
western spadefoot	*Spea hammondii*	*S/SSC*	2
	Reptiles		
Temblor legless lizard	*Anniella alexanderae*	*Under Review / Candidate*	2
western pond turtle	*Actinemys marmorata*	*/SSC*	2
California glossy snake	*Arizona elegans occidentalis*	*--/SSC*	1, 2
blunt-nosed leopard lizard	***Gambelia sila***	***FE/CE, FP***	**1, 2**
San Joaquin coachwhip	*Masticophis flagellum ruddocki*	*--/SSC*	2
coast horned lizard	*Phyrnosoma blaimvillii*	*/SSC*	2
	Birds		
burrowing owl	*Athene cunicularia*	*S/SSC*	1, 2
tricolored blackbird	***Agelais tricolor***	***CT***	**2**
loggerhead shrike	*Lanius ludovicianus*	*/SSC*	2
California horned lark	*Erempohila alpestris actia*	*/WL*	2
prairie falcon	*Falco mexicanus*	*/WL*	2
Le Conte's thrasher	*Toxostoma lecontei*	*S/SSC*	2
Swainson's hawk	***Buteo swainsoni***	***CT***	**1, 2**
	Mammals		

[433] Stafford Letter at 148; Letter from CDFW to CalGEM, Elk Hills Oil Field, Kern County, Special-Status Species Information from CDFW.

Nelson's (San Joaquin) antelope squirrel	***Ammospermophilus nelsoni***	***S/CT***	**1, 2**
giant kangaroo rat	***Dipodomys ingens***	***FE/CE***	**1, 2**
short-nosed kangaroo rat	*Dipodomys nitratoides brevinasus*	*S/SSC*	1, 2
Tipton kangaroo rat	***Dipodomys nitratoides nitratoides***	***FE/SE***	**1, 2**
Buena Vista Lake shrew	Sorex *ornatus relictus*	*FE/SSC*	2
Tulare grasshopper mouse	*Onychomys torridus tularensis*	*S/SSC*	2
San Joaquin pocket mouse	*Perognathus inornatus*	*--/SSC*	1
American badger	*Taxidea taxus*	*--/SSC*	1, 2
San Joaquin kit fox	***Vulpes macrotis mutica***	***FE/CT***	**1, 2**

Federal Designation

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

State Designation

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

Many of these same species were listed in the letter the Center for Biological Diversity, Central Valley Air Quality Coalition, and Central California Environmental Justice Network submitted in response to the Notice of Preparation for the Project, based on species found in the U.S. Geologic Survey quadrangles surrounding the Project site.

2. The Recirculated Draft EIR fails to respond to comments from the public and the California Department of Fish and Wildlife.

As an initial matter, between the original Draft EIR and the Recirculated version, there are no substantive changes to survey methodologies or mitigation measures. The County therefore ignored comments from the public as well as CDFW without explanation or support for doing so.

For example, the Recirculated Draft EIR's Summary of Written Public Comments notes that, when commenting on the original Draft EIR, the CDFW "[r]ecommended *specific mitigation measures for each species*, such as conducting surveys, avoiding disturbance to habitat . . . ."[434] The County did not, however, propose mitigation measures for each species, as detailed below. In fact, the Recirculated (and original) Draft EIR entirely *excludes* some species,

[434] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1 (emphasis added); see also *id.* at 1065, CDFW Letter.

like the Tipton kangaroo rat, or otherwise fails to offer mitigations that evidence shows would *reduce* impacts to species, such as the blunt-nosed leopard lizard. In another example, the CDFW instructed the County to "obtain incidental take authorization;"[435] our organizations' comment letter pointed out that any existing ITP is deficient. The County ignores this ITP requirement as well.

The Recirculated Draft EIR also fails, without explanation, to take up the CDFW's specific requests to (1) clarify Mitigation Measure 4.4-1(B), noting that it is unclear what that Measure means for implementation of protocol surveys; (2) analyze the potential direct or indirect impacts to the Elk Hills Conservation Area and the associated listed species, including to ensure that infrastructure and injected CO_2 avoid the protected area's boundary in order "to minimize the potential for CO_2 leaks impacting the rare species"; (3) consult with the U.S. Fish and Wildlife Service; and (4) to adequately describe the Project's impacts to streams, pursuant to Fish and Game Code section 1600 et seq.[436]

The CDFW made clear in its comment on the original Draft EIR that these and other recommendations were "[i]n addition to" its comments sent to the County in 2022[437] and that "the following modifications and/or edits be incorporated into the final EIR, including proposed avoidance, minimization, and compensatory measures, prior to its adoption by Kern County."[438] The County utterly fails to reflect the CDFW's expert advice in the Recirculated Draft EIR.

3. The Recirculated Draft EIR must address construction and operation impacts to species.

While the Recirculated Draft EIR claims there are no significant and unavoidable Project impacts to biological resources, this conclusion misses the mark and reflects a failure to account for the evidence showing that operating CCS projects can be severely detrimental, or even deadly, to wildlife, plants, and habitats.

The Project poses risks to biological resources from leakage and uncontrolled blowouts of compressed CO_2 from pipelines and injection wells. Compressed CO_2 forms a low dense cloud that can spread long distances from the release site and sicken and asphyxiate living things, including plants and animals.[439] CO_2 injection in oil fields and CO_2 pipeline transport have resulted in leakage and blowouts in several states that have caused wildlife deaths and significant habitat degradation. For example, a CO_2 injection well blowout in the Tinsley field, Mississippi, took 37 days to bring under control and killed deer, birds, fish, and other animals.[440] The

[435] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on Draft EIR (Dec. 2023) at 1.
[436] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on Draft EIR (Dec. 2023) at 1072–73, CDFW Letter.
[437] Aside from the CDFW's recommendations described in this section, we describe and reference other recommendations from the CDFW, sent during the Notice of Preparation and original Draft EIR periods, throughout this comment letter.
[438] *Id.* at 1068.
[439] See Pipeline Safety Trust and AccuFacts, *CO_2 Pipelines: Dangerous and Under-Regulated* (Mar. 2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
[440] Zegart, *The Gassing of Satartia*.

blowout ejected CO_2 along with mud and drilling fluids, requiring the removal of 27,000 tons of drilling mud and contaminated soil and 32,000 barrels of liquids, and causing extensive habitat damage.[441] Other examples of CO_2 harms to wildlife and plants, and research on this topic, include:

- In 1986, a sudden, catastrophic release of CO_2 from Lake Nyos in Cameroon killed 1,700 people and 3,000 cattle. The CO_2 spread 10 km from the lake. Bird, insect, and small mammal populations in the area were not seen for at least 48 hours after the event.[442]
- Experiments with controlled injections of CO_2 into soil showed adverse effects on plants in response to CO_2 exposure. Biomass changes were seen in all plants studied; for example, clover plants decreased by 79% while grass decreased by 42%. The researchers' overarching conclusion was that elevated concentrations of soil CO_2 damages both soil microbiology and growing vegetation.[443]
- Other research on CO_2 and plants showed reduced plant growth and extensive mortality where CO_2 concentrations were greatest in the soil. For the plants that survived, root and shoot growth was significantly lower than in controls. Reproductive variables such as number of seeds per plant and seed dry weight per plant were also reduced compared to controls.[444]

The Recirculated Draft EIR's analysis must also consider the impacts posed to burrowing species in the Project site, including the area in which the CO_2 plume is expected to spread. (The Recirculated Draft EIR acknowledges that construction could cause loss of burrows and dens during construction at p. 4.4-40, but not during Project operation.) Burrowing animals are particularly vulnerable to death from CO_2 suffocation in the event of CO_2 pipeline or injection well blowout, since released CO_2 could fill nearby burrows where animals are resting or retreating. Federally listed burrowing species in the Project area include the San Joaquin kit fox, San Joaquin antelope squirrel, giant kangaroo rat, and blunt-nosed leopard lizard.

Finally, the County must explain why, in the Recirculated Draft EIR, it removed all references to the "Biological Study Area" (BSA) and replaced that language with "project area." The original Draft EIR defined the BSA as including "everything within the limits of the project footprint (the carbon capture and storage [CCS] Surface Land Area) and a 250-foot survey buffer, where feasible."[445] We argued in our comment letter on the original Draft EIR that the Project's impacts to species from CO_2 leaks and blowouts must be considered within the scope of

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[441] Amy, *Oil spills in Mississippi, Alabama lead to $3.5 million in penalties for the company,* Clarion Ledger (Apr. 30, 2019), https://www.clarionledger.com/story/news/2019/04/30/oil-spills-penalties-mississippi/3625587002/.
[442] Kling, G.W. et al., *The 1986 Lake Nyos Gas Disaster in Cameroon, West Africa*, 236 Science 169 (1987).
[443] Smith, K.L. et al., *Environmental Impacts of CO2 Leakage: Recent Results from the ASGARD Facility, UK*, 37 Energy Procedia 791 (2013).
[444] Al-Traboulsi et al., *Potential Impact of CO2 Leakage from Carbon Capture and Storage (CCS) Systems on Growth and Yield in Spring Field Bean*, 80 Environ. Exper. Botany 43 (2012).
[445] Draft EIR, Vol. 1 at 4.4-3.

the BSA. The County must explain a) why it removed the BSA; b) if removal of the BSA constitutes a change in how (and where) Project impacts were considered; c) why the maps in the Biological Resource section changed to no longer show the BSA's 250-foot buffer; and d) the reason for the change from BSA to project area in the Recirculated Draft EIR.

4. The Recirculated Draft EIR's reconnaissance surveys are deficient.

There are deficiencies in the reconnaissance surveys that the Recirculated Draft EIR relies upon to identify potentially impacted species. In evaluating whether a project will affect endangered, rare, or threatened species, lead agencies can use reconnaissance-level surveys—rather than protocol-level surveys or other methods—*only* where the choice of methodology is supported by substantial evidence.[446] Without explanation or evidence supporting its decision, the Recirculated Draft EIR notes that "[n]o protocol surveys were conducted."[447] And merely changing the name from the original Draft EIR's "reconnaissance surveys"[448] to "biological resource" surveys[449] without making any other changes in the content of surveys conducted does not resolve this error.

Of the 39 species CDFW identified as potentially occurring in the Project area (see Table 1 in section V.G.1), the Recirculated Draft EIR identifies just 27 that may be potentially affected by the Project following literature, database analysis, and reconnaissance surveys in September—December 2022. But the initial database review and reconnaissance/biological resource surveys were insufficient to identify all sensitive species that may potentially occur in the Project area. In particular, despite the poor timing of the reconnaissance/biological resource surveys to detect many species, the Recirculated Draft EIR relies on these sources to exclude the Tipton kangaroo rat and several plant species that CDFW has noted occur or have the potential to occur near the Project site, as explained further below.

a. Tipton Kangaroo Rat

The Tipton kangaroo rat (TKR) is a "keystone" species in the San Joaquin Valley because it provides important "components of the biological niche."[450] CDFW wrote in comments on the scoping phase of the Project that TKR "have been documented to occur near the Project site" and that suitable habitat is present for the species to "occupy or colonize the Project."[451] CDFW went on to recommend a trapping plan to determine the presence of TKR, to be reviewed and approved by CDFW prior to execution, and that "these surveys be conducted between April 1 and October 31, when kangaroo rats are most active and well in advance of ground- and/or vegetation-disturbing activities in order to determine if impacts . . . could occur."[452]

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[446] *Gray*, *supra*, 167 Cal.App.4th at 1124.
[447] RDEIR, Vol. 1 at 4.4-39.
[448] See, e.g., Draft EIR, Vol. 1 at 4.4-39.
[449] See, e.g., RDEIR, Vol. 1 at 4.4-39.
[450] RDEIR, Vol. 1 at 4.4-38.
[451] RDEIR, Vol. 2, App'x A.2: Comment Letters at 154.
[452] RDEIR, Vol. 2, App'x A.2: Comment Letters at 155.

Despite its importance and likelihood to appear in and use the Project site, the Recirculated Draft EIR fails almost entirely to acknowledge this species. First, contrary to CDFW's recommendation, the Biological Analysis Report did not include a trapping plan submitted to and approved by CDFW. Second, the Project's reconnaissance/biological resource survey did not take place in the recommended timeframe of between April 1 and October 1, but instead in winter, when—as one might expect—no Tipton kangaroo rats were observed. Rather than include this species for further evaluation in protocol-level surveys, the Project removed it from consideration with the following flimsy rationale: "The BSA is outside of the known geographic range (east of the California aqueduct) of the species."[453] This statement not only is not supported by substantial evidence, it is contradicted by multiple letters from CDFW.

The TKR should have been properly surveyed, as CDFW recommended, and included in the Recirculated Draft EIR as potentially occurring in the Project area to ensure it was analyzed and covered by mitigation measures.

b. Blunt-nosed Leopard Lizard

The Recirculated Draft EIR ignores the CDFW's concerns—expressed in both the Notice of Preparation comment and the agency's comment on the original Draft EIR—about survey protocols for the blunt-nosed leopard lizard (BNLL). According to CDFW, "[t]he Biological Resources section of the DEIR appears to rely primarily on reconnaissance level surveys conducted for the DEIR and ignores the substantial body of biological information collected within the [Elk Hills Oil Field]."[454] The CDFW went so far as to call the original Draft EIR's conclusion that no lizards were observed "*wholly misleading* given the extensive distribution of BNLL known to occur . . . as supported by decades of surveys and research."[455] Moreover, as the CDFW explains, "no other area within the range of BNLL [is] as extensively studied for the BNLL" as the Elk Hills oil field, and the populations of these lizards "are extremely dense" in portions of the oil field.[456] The CDFW recommends that the County disclose the species' "probability densities, ongoing monitoring routes and associated detections, and historical observations" to inform the CEQA analysis and related impacts to "this Fully Protected species."[457]

The Recirculated Draft EIR does none of what the CDFW asked, resulting in a CEQA document that continues to be not only "misleading," but also illegal. Instead, the Recirculated Draft EIR offers only that protocol-level and pre-construction surveys occurred three miles southwest of the Project area five years ago, in 2019; the document also names surveys conducted in several years prior.[458] The Recirculated Draft EIR does not, however, share results of those specific surveys, or as the CDFW requested, any probability densities, monitoring routes, or detections. The document says only in the aggregate, the separate Elk Hills

[453] RDEIR, Vol. 2, App'x C.1: Biological Analysis Report at 1701.
[454] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1068, CDFW Letter.
[455] *Id.* (emphasis added).
[456] *Id.*
[457] *Id.*
[458] RDEIR, Vol. 1 at 4.4-17.

Conservation Area's semi-annual monitoring since 1999 has yielded 475 BNLL detections.[459] This is utterly insufficient and unresponsive to what the CDFW requested.

c. San Joaquin Antelope Squirrel

The CDFW correctly notes that while the original Draft EIR indicated that reconnaissance surveys detected multiple occurrences of the San Joaquin antelope squirrel (SJAS), "no reference was made to the substantial body of SJAS detection data that exists for the [Elk Hills oil field]."[460] This species is considered "fairly widespread" throughout the field, and the agency recommended that the County disclose "OXY/CRC's ongoing SJAS monitoring and associated detections," along with historical observations, to better inform the CEQA analysis and mitigations.[461] The Recirculated Draft EIR does none of this, without explaining why.

d. Giant Kangaroo Rat

Like the species mentioned above, the CDFW points out that the original Draft EIR ignores "extensive giant kangaroo rat (GKR) survey data within [the Elk Hills oil field]" from OXY/CRC.[462] The survey areas "overlap substantially with the proposed Project boundaries" and are therefore highly relevant.[463] Despite this, the Recirculated Draft EIR ignores this evidence without explanation. The Recirculated Draft EIR also fails to take up the CDFW's recommendation to disclose ongoing monitoring, detections, and historical observations. Instead, the Recirculated Draft EIR only adds that surveys conducted between 2001-2005 and semi-annual monitoring in the Elk Hills Conservation Area showed 1,240 active signs of GKR.[464] This is short of what the CDFW said is needed "to better inform the CEQA impact analysis."[465]

e. Special Status Plants

CDFW identified multiple plant species that may be located in the Project area. The agency recommended in comments on the Notice of Preparation that Project sites should be surveyed "by a qualified botanist following the 'Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities' . . . . This protocol, which is intended to maximize detectability, includes the identification of reference populations to facilitate the likelihood of field investigations occurring during the appropriate floristic period."[466] The protocol is "meant to help people meet California Environmental Quality Act (CEQA) requirements for adequate disclosure of potential impacts to plants" and further recommends that field surveys be conducted multiple times during flowering or fruiting, when

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[459] *Id.*
[460] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1069, CDFW Letter.
[461] *Id.*
[462] *Id.*
[463] *Id.*
[464] RDEIR, Vol. 1 at 4.4-21.
[465] RDEIR, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1070, CDFW Letter.
[466] RDEIR, Vol. 2, App'x A.2: Comment Letters at 159.

plants will be evident and identifiable.[467] The Recirculated Draft EIR's methodology and recommendations are at odds with this protocol.

Surveys are particularly important because information in databases is voluntarily submitted and "obtained opportunistically and is often focused on protected lands or on lands where development has been proposed."[468] CDFW identified with aerial imagery that many plant species could be impacted by the development in the Elk Hills oil field, including Horn's milk vetch, slough thistle, alkali-sink goldfields, pale-yellow layia, and California alkali grass.[469] CDFW further stated that:

> [i]n order to adequately assess any potential impacts to biological resources, focused biological surveys are advised to be conducted by a qualified wildlife biologist during the appropriate survey period(s) in order to determine whether or not any special status species may be present within the well development areas and prior to any ground-disturbing activities. Survey results can then be used to inform the level of environmental review and identify any mitigation, minimization, and avoidance measures necessary to reduce potential impacts to special status biological resources to less than significant.[470]

The Project's Biological Analysis Report appears to recognize the importance of surveys to supplement information in databases. It says that "the absence of recorded occurrence in these databases at any specific location does not preclude the possibility that a special-status resource may be present, which is why site-specific surveys were undertaken."[471] The Recirculated Draft EIR, though, fails to conduct plant surveys in a manner that conforms with the CDFW recommendations and would produce meaningful results.

First, it is not clear if the determination of whether species had the potential to occur was made prior to or after reconnaissance/biological resource surveys.[472] And, if made after surveys, the "site-specific surveys" conducted for the Biological Analysis Report are not the same as the surveys recommended by CDFW to determine the species in the Project area and develop mitigations. For example, the Project conducted surveys between September and December, outside bloom times.[473] The Recirculated Draft EIR's Table 4.4-7 shows the "optimal blooming period[s]" for special-status plants with potential to occur as largely starting in March and April

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[467] CDFW, *Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities* (Mar. 2018) at 1.
[468] RDEIR, Vol. 2, App'x C.1: Biological Analysis Report at 2559.
[469] RDEIR, Vol. 2, App'x A.2: Comment Letters at 151.
[470] *Id.* at 146–47.
[471] RDEIR, Vol. 2, App'x C.1: Biological Analysis Report at 2559.
[472] *Id.* at 2560 ("The results of the database inquiries were reviewed to develop a comprehensive list of sensitive biological resources that may be present on or in the vicinity of the Project site (see Table A-1 in App'x A). This list was then evaluated against existing site conditions observed during the biological field surveys of the BSA to determine which special-status resources have the potential to occur and then the potential for impacts to those resources as a result of the implementation of the Project.").
[473] RDEIR, Vol. 1 at 4.4-57, Table 4.4-7.

and ending in May and June.[474] The Recirculated Draft EIR offers no explanation for conducting plant surveys outside of these blooming periods.

Further, there is also no evidence that the surveyors possess specific plant knowledge, have experience "conducting floristic botanical field surveys," or that the surveys followed other requirements in CDFW's 2018 protocols for surveying document.[475] CDFW's protocol specifically states that it is inappropriate to conduct "'[f]ocused surveys' that are limited to habitats known to support special status plants or ***that are restricted to lists of likely potential special status plants***" because they "are not adequate to identify all plants in a project area to the level necessary to determine if they are special status plants,"[476] but this is exactly what the Recirculated Draft EIR proposes.[477]

5. The Recirculated Draft EIR's proposed mitigation measures are unsupported and/or insufficient.

A large number of species-specific mitigation measures lack support, ignore scientific evidence, and/or expert agency recommendations submitted during the scoping period, fail to adhere to legal requirements, and ultimately must be substantially revised. Further, the Recirculated Draft EIR lacks entirely mitigations for specific species or offers vague and/or yet-to-be-determined mitigation plans that must be specified and recirculated for comment from the public and experts.

a. Blunt-nosed Leopard Lizard

The BNLL is a Fully Protected species in California and the proposed Project is located in "what is known as the highest quality BNLL habitat" within the Elk Hills oil field.[478] The Recirculated Draft EIR fails to provide sufficient mitigation measures to detect the species and avoid take, just as it fails to adequately respond to concerns, evidence, and suggestions offered by the CDFW during the Project scoping period.

<u>Mitigation Surveys</u>

In addition to the failures of the population surveys noted above, the County's proposed mitigation surveys are insufficient. They provide that "[n]o more than one year prior to ground disturbing activities, focused surveys . . . shall be conducted in all potential" habitat" (MM 4.4-9(b)); as well as "[w]ithin 30 days before any ground-disturbing activities in special-status species habitat, the qualified biologist shall conduct a pre-disturbance survey" (MM 4.4-1(C)). But as the CDFW pointed out in their scoping comment: "Protocol-level surveys for BNLL are not synonymous with 30-day 'preconstruction surveys' often recommended for other wildlife species. In addition, the BNLL protocol specifies different survey effort requirements based on whether the disturbance results from maintenance activities or if the disturbance results in habitat

[474] *Id*.
[475] CDFW, *Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities* at 11.
[476] *Id.* at 4.
[477] RDEIR, Vol. 1 at 4.4-57.
[478] RDEIR, Vol. 2, App'x A.2: Comment Letters at 150.

removal (CDFW 2019)."[479] The Recirculated Draft EIR does not address the difference between protocol-compliant surveys and 30-day preconstruction surveys, or the difference in survey type based on Project activity and impact. The BNLL mitigation measures for surveys must provide more specifics on how the proposed surveys will comply with the nuances in the protocols.

Further, the County's mitigation measures must be clearer on the timing of the one-year survey and provide more explanation for how the timing will fit with the BNLL's complex lifecycle and the fact that the species can remain below ground for years at a time. MM 4.4-9 says only that "focused surveys . . . shall be conducted" within a year of construction. The BNLL breeds from May to June, and eggs hatch in July and August.[480] The species is then active during the day in the spring, summer, and fall months, though adult activity decreases during the hot summer months of July and August, just as the hatchlings emerge from the burrows.[481] At that point, adults generally retreat into their burrows for the winter.[482] Hatchlings stay out until October or November, before going into burrows.[483] Adults are capable of remaining below ground for two winters when poor environmental conditions, such as drought, are present.[484] The Mitigation Measure for longer-term surveys must therefore account for detecting both adult and juvenile BNLLs, as well as the fact that adults may remain underground for two years in a row.

Deferred Mitigation

MM 4.4-9(c) says that if BNLL are found during surveys, an "avoidance plan shall be prepared." The Mitigation Measure then recommends certain minimum actions to be included in the plan, such as a Worker Awareness Program and a speed limit.[485]

But the County cannot defer creation of a mitigation measure until a problem is detected. Under the CEQA rule against improper deferred mitigation, an EIR may not outline a mitigation measure in overly general terms, leaving the details to be decided at a later time, without setting performance standards or showing how the impact can be mitigated as described in the EIR.[486] Formulation of a measure's specific requirements for biological impacts may be permissible if the measure refers to the options that will be considered and the measure identifies specific

[479] RDEIR, Vol. 2, App'x A.2: Comment Letters at 150.
[480] California Herps, *Blunt-Nosed Leopard Lizard - Gambelia sila*, https://californiaherps.com/lizards/pages/g.sila.html (last accessed Mar. 1, 2024).
[481] U.S. Fish and Wildlife Service (FWS), *Blunt-Nosed Leopard Lizard*, https://www.fws.gov/species/blunt-nosed-leopard-lizard-gambelia-silus (last accessed Mar. 1, 2024).
[482] *Id.*
[483] *Id.*
[484] *Id.*
[485] *Id;* see also MM 4.4-9(c)(3) (if BNLL are detected during construction, "construction shall cease within a 250-foot radius" until additional measures are determined).
[486] CEQA Guidelines, §15126.4(a)(1)(B); *Preserve Wild Santee v. City of Santee* (2012) 210 CA4th 260, 280 (rejected measure calling for management of species without specifying performance standards or other guidelines for that management); *San Joaquin Raptor Rescue Ctr.*, *supra*, 149 CA.4th at 669 (measure specifying that future surveys for special status species be completed and undefined habitat management plan be developed in response to surveys found legally inadequate).

performance standards.[487] All of these required safeguards and specifics are lacking in MM 4.4-9(c).

Cumulative Analysis

The CDFW recommended in the scoping period that the County perform a "robust cumulative impact analysis" of the BNLL because of the "significant loss of habitat for the species," the fact that the Project area and surrounding lands "contain some of the highest quality remaining habitat" for the BNLL, and that any "ground disturbing activities . . . may have the potential to significantly impact" populations.[488] The Recirculated Draft EIR entirely ignores this recommendation and it is not reflected either in the analysis or the mitigation measures. There is no explanation for why CDFW's recommendation was ignored. The County must take up this recommendation and adjust its analysis and mitigation measures accordingly.

Buffer Zones

The mitigation measures for BNLL buffer areas fail to match the analysis and evidence CDFW provided in the scoping period. CDFW sought to determine the appropriately sized buffer to create a "reasonable chance of preventing take."[489] The agency reviewed the best available scientific information on the area which individual BNLL use and the distances that individuals are known to move between points.[490] They summarized relevant findings and concluded that the buffer area would need to be 164 acres *at a minimum* to avoid take.[491]

Rather than grapple with this informed and reasoned recommendation, the mitigation measures for the BNLL are vastly under-protective. MM 4.4-9(a) provides only a 50-foot buffer where ground-disturbing activities could impact suitable burrows. MM 4.4-9(b) prescribes a 250-foot buffer if the species is detected. (Even here, it is unclear what "detected" means—the same Mitigation Measure states that no buffer is needed if no BNLL "is observed," but "observation" may not be the same as detecting signs of the lizard.)[492]

The Recirculated Draft EIR's prescribed 50-foot buffer is 2% of the CDFW recommendation, and the 250-foot buffer only 10% of the CDFW recommendation. Moreover,

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[487] *Clover Valley Found. v. City of Rocklin* (2011) 197 CA.4th 200, 237 (requirement that permits be obtained from Department of Fish and Wildlife and Corps of Engineers served as performance standards supporting agency's determination that impact to listed species and its habitat would be mitigated); see also *Rialto Citizens for Responsible Growth v. City of Rialto* (2012) 208 CA.4th 899, 945; *Cal. Native Plant Society*, *supra*, 172 CA.4th at 621; *Endangered Habitats League, Inc. v. County of Orange* (2005) 131 CA.4th 777, 794; *Defend the Bay v. City of Irvine* (2004) 119 CA.4th 1261, 1275.

[488] RDEIR, Vol. 2, App'x A.2: Comment Letters at 150.

[489] RDEIR, Vol. 2, App'x A.2: Comment Letters at 151.

[490] RDEIR. Vol. 2, App'x A.2: Comment Letters at 151.

[491] RDEIR. Vol. 2, App'x A.2: Comment Letters at 152–53 (going on to explain that "a reasonable plan for avoidance is to assume that the lizard might utilize up to 98.8 acres in any direction from where it was observed," and assuming a circular home range, the diameter would be 2340.8 feet, or a 395-acre circle as a buffer).

[492] See also MM 4.4-9(c)(3) (if BNLL are detected during construction, "construction shall cease within a 250-foot radius until additional measures are determined").

the evidence the CDFW analyzed showed the *minimum* home range for the BNLL to be 1.1 acres (with other findings extending up to nearly 22 acres). One acre is 660 feet long—meaning the buffers in the mitigation measures are not even half of the bare minimum space needed to protect the species. These buffers simply fall far short of what is needed to meet the County's legal obligations and avoid take of the species. The Recirculated Draft EIR offers no explanation for running counter to the best available scientific evidence of what may be reasonable to avoid take.

b. San Joaquin Kit Fox

There is both high likelihood of San Joaquin Kit Fox (SJKF) presence and occupation of the Project site and a need for strong mitigation measures. Per the CDFW, SJKF "may be attracted to the Project area due to the type and level of ground-disturbing activities and the loose, friable soils resulting from intensive ground disturbance."[493] Mitigations must eliminate or substantially limit the likelihood of den collapse, inadvertent entrapment, reduced reproductive success, reduction in health and vigor of young, and direct mortality of individuals.[494]

The current SJKF mitigation measures are deficient and fail to align with scientific evidence and/or legal requirements in several ways. First, the CDFW was clear in its scoping comment that avoiding Project impacts to SJKF "is likely infeasible," and this Project warrants consultation with CDFW and acquisition of a SJKF-specific ITP prior to ground-disturbing activities.[495] This is because the "existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity."[496]

Second, while MM 4.4-6 provides for buffers around potential and confirmed dens, it also directs that any dens that "cannot be avoided" will be removed. Calling for den removal fails to align with evidence provided during the scoping period that kit fox relocation is complex and likely to fail.[497] The Mitigation Measure further fails to propose how exactly den "excavation" will occur, if/where relocation will happen, and how relocation will take into account critical factors such as expense, available habitat, impact on existing populations, and documentation.[498] Den removal also implicates species take which, as noted below, requires a separate ITP than what the County currently claims covers Project activities.[499] The Mitigation Measure also fails to acknowledge the USFWS's guideline that occupied natal or pupping dens will not be destroyed until the foxes have vacated, thus requiring postponement of Project

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[493] RDEIR, Vol. 2, App'x A.2: Comment Letters at 153.
[494] *Id.*
[495] *Id.* at 154.
[496] *Id.*
[497] Bremner-Harrison, S. et al., *Feasibility and Strategies for Translocating San Joaquin Kit Foxes to Vacant or Restored Habitats* (2007), https://esrp.csustan.edu/publications/pdf/esrp_2007_kitfoxreloction_w.pdf.
[498] See *id.* at 3-7.
[499] See, e.g., FWS, *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* at 4 (2011), https://www.fws.gov/sites/default/files/documents/survey-protocols-for-the-san-joaquin-kit-fox.pdf (emphasizing that "Destruction of any known or natal/pupping kit fox den requires take authorization/permit from the Service" and that if "at any point during excavation, a kit fox is discovered inside the den, the excavation activity shall cease immediately and monitoring of the den as described [therein] should be resumed").

activities.[500] Details such as these must be included in the mitigation measures so that all parties (including the Project developer, workers, and local regulators) are aware of their obligations and limitations.

Third, other measures to project the SJKF do not align with CDFW and USFWS recommendations. (Of note, MM 4.4-6 directs the reader to other measures "including capping pipes, covering trenches, adding exit ramps to excavated areas" at MM 4.4-15. But MM 4.4-15 concerns wetlands and waters, whereas 4.4-13 concerns additional measures to avoid adverse impacts to species, such as speed limits and covering open trenches. This drafting error should be corrected.) For example, the CDFW recommends all perimeter fencing be raised 5 to 7 inches above ground level to allow SJKF movement through the Project site and to minimize impacts to SJKF habitat connectivity.[501] MM 4.4-13(h) prescribes perimeter fencing to be 4 inches off the ground—meaning, this fencing would be too short for the SJKF to pass. The USFWS also recommends that new sightings of kit fox shall be reported to the California Natural Diversity Database.[502] The County should amend its mitigation measures to take into account these expert agency recommendations.

c. Giant Kangaroo Rat, Tipton Kangaroo Rat, Short-Nosed Kangaroo Rat, and San Joaquin Antelope Squirrel

As an initial matter, the Recirculated Draft EIR must correct its omission of the TKR. According to CDFW, the GKR, TKR, and Short-Nosed Kangaroo Rat (SNKR) "have been documented to occur near the Project site (CDFW 2022), and the Project Area supports some of the best GKR habitat present in the Elk Hills oil field."[503] It is unclear why the Recirculated Draft EIR fails to discuss the TKR in the Biological Resources section.[504] This omission must be corrected by including an analysis of research and impacts, and inclusion of species-specific mitigation measures.

Regarding surveys, the CDFW recommended trapping surveys for the GKR, TKR, and SNKR, to be conducted according to trapping plans developed in consultation with CDFW.[505] CDFW further recommended that these surveys be conducted between April 1 and October 31, when kangaroo rats are most active and well in advance of ground- and/or vegetation-disturbing activities.[506] Once completed, they requested that all survey results be sent to CDFW.[507] Without explanation or evidence to explain why it would not have to conduct such surveys (including for the TKR), the Recirculated Draft EIR does not take up any of these recommendations. Relatedly,

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[500] *Id.* at 4 (2011).
[501] RDEIR, Vol. 2, App'x A.2: Comment Letters at 154.
[502] FWS, *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* at 6.
[503] RDEIR, Vol. 2, App'x A.2: Comment Letters at 154; *see also* RDEIR, Vol. 1 at 4.4-38 (noting that the USFWS published a recovery plan for species in the San Joaquin Valley, including the TKR, identifying it as a "keystone" species).
[504] RDEIR, Vol. 1 at Table 4.4 (listing the TKR but providing no further information, unlike other species).
[505] RDEIR, Vol. 2, App'x A.2: Comment Letters at 154.
[506] *Id.*
[507] *Id.*

the CDFW recommended seeking ITPs upon detection of any of the protected rat species; it does not appear the Project has done this.[508]

While the Recirculated Draft EIR's 50-food den buffer aligns with the CDFW recommendation,[509] the mitigation measures ignore the CDFW's caution that buffers may not be sufficient to ensure that the species can "freely disperse to and from burrows."[510] Inhibiting the movement of these protected species could be considered "capture" and/or result in prohibited species take.[511] To address this, the CDFW recommended that no burrow be surrounded more than 180 degrees around by development activities.[512] The Recirculated Draft EIR ignores this recommendation without explanation or evidence. The mitigation measures should adopt this 180-degree protection in addition to buffers around rodent dens.

The issues above are similar with the San Joaquin antelope squirrel (SJAS), which is known to occur throughout the Elk Hills oil field.[513] Like the rat species, the CDFW recommended that no SJAS burrow be surrounded more than 180 degrees around by development activities.[514] The Recirculated Draft EIR fails to adopt this measure and fails to offer explanation or evidence that omitting this protection would somehow avoid capture and/or take. The CDFW also informed the County of the need for a separate ITP permit for SJAS take.[515]

d. Swainson's Hawk

Swainson's hawks have been documented to occur in the areas bordering the Elk Hills oil field, and the habitat type present provides suitable foraging and nesting habitat.[516] Despite this, the Recirculated Draft EIR lacks any mitigation measures specific to the species.

The CDFW recommended specifically for the Swainson's hawk that, upon discovery of an active nest, a minimum half-mile buffer be delineated and that such a buffer be maintained until the breeding season ends or a qualified biologist determines the birds have fledged.[517] Instead, MM 4.4-8 (which broadly covers all bird nests) provides that if a nest is detected, it will be continuously surveyed for 24 hours to establish behavior baseline prior to construction; then continuously monitored to detect any behavioral changes. Monitoring of a nest falls short of an immediate buffer and the Recirculated Draft EIR does not provide evidence that simple monitoring will be sufficient to reduce adverse impacts to the species. Further, the Measure does not clarify who will do the 24-hour monitoring or the continuous behavioral monitoring; at the very least this must be a qualified biologist selected by the County.

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[508] *Id.* at 154–55 (stating that "the existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity").
[509] RDEIR, Vol. 1 at Table 4.4-6.
[510] RDEIR, Vol. 2, App'x A.2: Comment Letters at 154.
[511] *Id.*
[512] *Id.*
[513] *Id.* at 156.
[514] *Id.*
[515] *Id.* at 157.
[516] *Id.*
[517] *Id.* at 158.

The Recirculated Draft EIR also entirely fails to address the loss of Swainson's hawk foraging habitat and tree removal, two concerns CDFW raised during the scoping period.[518] The CDFW provided reasoned and supported recommended mitigations to address these concerns that must be incorporated into the Recirculated Draft EIR.

e. Burrowing Owl

Burrowing owls have been documented in the Project vicinity, per CDFW.[519] The Project has the "potential to significantly impact local [] populations" and, and as described in CDFW's "Staff Report on Burrowing Owl Mitigation" (CDFG 2012), "excluding and/or evicting [burrowing owls] from their burrows is considered a potentially significant impact under CEQA."[520]

The CDFW's Staff Report is clear that Project-specific CEQA mitigation is important for burrowing owls and unless otherwise provided in a state, local, or regional conservation strategy, mitigation measures must incorporate the following four principles: 1) use of the precautionary principle; 2) use of mitigation effectiveness monitoring and reporting, as well as adaptive management; 3) protect and conserve owls in wild, semi-natural, and agricultural habitats; and 4) protect and conserve natural nest burrows or surrogates.[521] The Staff Report then lists best practices for mitigation measures grounded in scientific literature.[522] These include, broadly, avoidance, pre-construction surveys, site surveillance, and buffer zones.[523]

The Recirculated Draft EIR does not take the CDFW's scoping comment or Staff Report fully into account, leaving its burrowing owl mitigations insufficient to reduce adverse impacts and unsupported by any evidence.

First, accurate surveys to detect burrowing owl presence is key, and CDFW suggested during the scoping period that the Project conduct "three or more surveillance surveys" with each visit occurring at least three weeks apart during peak breeding season (April 15 to July 15).[524] Mitigation Measure 4.4-1 provides only that "any required focused/protocol surveys shall be conducted . . . with protocol survey timelines." The Recirculated Draft EIR does not address the guideline for three or more surveillance surveys for owls, nor does it contain evidence or an explanation for why this approach would not be taken.

Second, MM 4.4-4 provides that burrowing owls present in the Project area or within 500 feet outside the breeding season "may be moved away . . . using passive relocation techniques." While this measure pledges to follow CDFW guidelines, the Recirculated Draft EIR fails to acknowledge that according to the CDFW, "excluding birds from burrows is not a take

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[518] *Id.*
[519] *Id.* at 160.
[520] *Id.*
[521] CDFW, *Staff Report on Burrowing Owl Mitigation, State of California* (March 7, 2012) at 3–4, https://www.sandiegocounty.gov/content/dam/sdc/pds/ceqa/JVR/AdminRecord/IBR/RTCReferences/3a%20CDFG%202012_Staff%20Reports%20on%20Burrowing%20Owl%20Mitigation.pdf.
[522] *Id.* at 8.
[523] *Id.* at 8–10.
[524] RDEIR, Vol. 2, App'x A.2: Comment Letters at 160.

avoidance, minimization, or mitigation method and is instead considered a potentially significant impact under CEQA."[525] The Recirculated Draft EIR must therefore acknowledge that displacing owls is an impact and analyze it as such. Should MM 4.4-4 maintain the approach of displacing owls, it must also incorporate the CDFW's guideline that burrow exclusion be conducted only by qualified biologists and only during the non-breeding season, and that occupied burrows be replaced with artificial ones at a ratio of 1:1.[526]

Finally, there is no logical connection between the full suite of impacts to burrowing owls named in the Recirculated Draft EIR and the mitigation measures named. The document acknowledges that "[n]oise, vibration, and increased human activity" from construction "could alter the daily behaviors of individual owls and affect foraging success, displace owls from their burrows, or lead to nest failure."[527] The Recirculated Draft EIR then claims MMs 4.4-1, -3, -4, -11, and -13 "would reduce impacts,"[528] but these Measures on their face do not fully address the impacts. MM 4.4-1 concerns surveys, MMs 4.4-3 and -4 address buffers and owl nest exclusion, MM 4.4-11 describes worker education, and MM 4.4-13 lists additional measures such as trash and dust control. The Measures listed are a start, but the Recirculated Draft EIR does not fully connect how they will address noise, vibration, and other impacts that could alter the daily behaviors of owls; the impacts are therefore left unmitigated.

f. Nocturnal Species

There are six protected nocturnal species in the Project area,[529] but the mitigation measures fail to adequately reduce impacts to these species (and other species) from the array of nighttime Project activities expected to occur.

As an initial matter, the Biological Resources section acknowledges that construction could occur at night and therefore require lighting that may affect diurnal and nocturnal wildlife.[530] But elsewhere in the document, the Recirculated Draft EIR states that nighttime Project activities could include "drilling activities, vehicle and equipment activities supporting drilling, and safety and security lighting for areas, such as construction yards, work areas, vehicle and equipment parking areas, and staging and laydown areas,"[531] and that Class VI well drilling "typically run[s] continuously, 24 hours a day" for "up to 60 days."[532] The full range of nighttime activities mentioned in other parts of the Recirculated Draft EIR must be incorporated, analyzed, and mitigated in the Biological Resources section.

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[525] *Id.* at 161 (citing the CDFW Staff Report).
[526] *Id.* at 161.
[527] RDEIR, Vol. 1 at 4.4-46.
[528] *Id.*
[529] The species are the California glossy snake, RDEIR, Vol. 1 at 4.4-44, 4.4-18; the giant kangaroo rat, *id.* at 4.4-22 (noting that "suitable burrows with diagnostic signs of kangaroo rat were observed" during surveys); the short-nosed kangaroo rat, *id.* at 4.4-22; the San Joaquin pocket mouse, *id.* at 4.4-22; the American badger, *id.* at 4.4-23 (noting that "dens displaying signs consistent with the use of a badger were observed" in the Project area); and the San Joaquin kit fox, *id.* at 4.4-23.
[530] RDEIR, Vol. 1 at 4.4-40.
[531] RDEIR, Vol. 1 at 4.1-24.
[532] RDEIR, Vol. 1 at 4.1-25.

Perhaps because of this disconnect, the only nighttime-related mitigation measure for species merely directs use of "directing lighting" and compliance "with applicable lighting mitigation measures."[533] Nighttime lighting is harmful to nocturnal species, but lighting is far from the only impact of nighttime construction and other activities that needs to be mitigated. (Moreover, the lighting mitigation is far too vague to be evaluated or measured and must be revised to include specifics and information about enforcement.) For example, the San Joaquin kit foxes "are known to sometimes rest and play near the den entrance in the afternoon, but most above-ground activities begin near sunset and continue sporadically throughout the night."[534] Accordingly, for that species, the U.S. Fish and Wildlife Service recommends that "[n]ight-time construction should be minimized" and if it does occur, "then the speed limit should be reduced to 10-mph" and "[o]ff-road traffic outside of designated project areas should be prohibited."[535]

The County must therefore develop mitigation measures to address the full array of impacts to nocturnal species from activities such as traffic, noise, vibrations, and continuous drilling. The County must also develop measures to address impacts to daytime species whose rest and other behaviors might be disrupted by nighttime disturbances and continuous drilling.

g. Worker Environmental Awareness Program

Mitigation Measure 4.4-11 to create a Worker Environmental Awareness Program is a good start but, as written, falls short of the County's legal requirements and could benefit from adopting recommendations by other agencies.

For one, the Recirculated Draft EIR defers development of the program, stating only in MM 4.4-11 that it "shall be developed." As noted earlier in this comment section, the County cannot defer development of a mitigation measure and instead must provide specifics prior to finalizing the Recirculated Draft EIR. A worker educational program is not the type of mitigation that requires further data or inputs from operations to prescribe measures, nor is it impractical or infeasible to devise the specifics of such a program now.[536]

One template the County could consider comes from the USFWS regarding the SJKF. They recommend an employee education program that does the following:

> The program should consist of a brief presentation by persons knowledgeable in kit fox biology and legislative protection to explain endangered species concerns to contractors, their employees, and military and/or agency personnel involved in the project. The program should include the following: A description of the San Joaquin kit fox and its habitat needs; a report of the occurrence of kit fox in the project area; an explanation of the status of the species and its protection under the Endangered Species Act; and a list of measures being taken to reduce impacts to the species during project construction and implementation. A fact sheet

[533] RDEIR, Vol. 1 at 4.4-59.
[534] FWS, *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* at 3.
[535] *Id.* at 5.
[536] See, e.g., *Defend the Bay v. City of Irvine* (2004) 119 Cal.App.4th 1261, 1275; *Preserve Wild Santee*, *supra,* 210 Cal.App.4th at 281; CEQA Guidelines, § 15126.4(a)(1)(B).

conveying this information should be prepared for distribution to the previously referenced people and anyone else who may enter the project site.[537]

This type of thorough education is appropriate for all protected species that are or could occur at the Project site. These materials must be developed and shared with the public and decisionmakers prior to finalizing and certifying the Recirculated Draft EIR.

Similarly, MM 4.4-12 provides that "wildlife found that might have been affected by exposure to CO_2 shall immediately cause a shutdown of all injection operations." This measure is important and should therefore be incorporated into the Worker Environmental Awareness Program, along with other information about exactly *how* to identify wildlife suffering symptoms of CO_2 exposure.

h. Cumulative Impacts and Mitigations

The Recirculated Draft EIR concludes that "the cumulative impacts of the project when combined with other known and unknown projects, would be significant and unavoidable" for biological resources.[538] The Recirculated Draft EIR then offers no additional mitigation measures beyond the ones proposed to address direct impacts.[539]

The Recirculated Draft EIR opts not to independently consider and evaluate potential cumulative impacts to biological resources because of the *Final Environmental Impact Report—Revisions to the Kern County Zoning Ordinance—2015(C) Focused on Oil and Gas Local Permitting*, referred to in the EIR as the Oil and Gas EIR.[540] The relationship to this Recirculated Draft EIR is somewhat opaque. The County uses the Oil and Gas EIR "as a source of information regarding cumulative impacts," but supposedly "does not rely" on it "for purposes of tiered review under CEQA."[541] By way of further explanation, the Oil and Gas EIR's information "provides evidence for the record of the analysis of cumulative impacts" for activities included in the Project.[542]

We agree that CEQA Guidelines section 15152 guides whether the County can tier to a previous analysis, but the County's supposed use but non-reliance on the Oil and Gas EIR is unconvincing. Per the Guidelines, "tiering" is defined as "using the analysis of general matters contained in a broader EIR" with later EIRs, incorporating by reference the general discussions from the broader EIR, and concentrating the later EIR solely on the issues specific to the later project.[543] This definition of tiering describes how the County is using the Oil and Gas EIR for this Project—meaning, the County is tiering to the challenged EIR, even if it claims not to be.

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[537] FWS, *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* at 6.
[538] RDEIR, Vol. 1 at 4.4-67.
[539] *Id.* at 4.4-66.
[540] *Id.* at 4.4-65 to 4.4-66.
[541] *Id.* (citing CEQA Guidelines, § 15152).
[542] *Id.* at 4.4-66.
[543] CEQA Guidelines, § 15152(a).

6. The Recirculated Draft EIR's reliance on a prior conservation easement deed for Endangered Species Act coverage is improper.

It is unclear to what extent Kern County proposes to rely on previously issued plans for Endangered Species Act coverage for the Project, but reliance on existing coverage through take permits is improper. As the Recirculated Draft EIR recognizes, unauthorized take of species is unlawful, and the County must have an ITP to cover any species take.[544] Yet the Recirculated Draft EIR claims that California Resources Corporation has an ITP from 2012, pointing to Appendix C.2. The Recirculated Draft EIR also references an "Elk Hills Habitat Conservation Plan" but does not provide the plan anywhere in the appendices.[545]

The Recirculated Draft EIR's discussion of ITP coverage is problematic for several reasons. First, the document provided in Appendix C.2 (both in the original and Recirculated Draft EIR) is not an ITP or Habitat Conservation Plan—it is a conservation easement deed for conservation areas that largely do not overlap with the Project site.[546] The document mentions only a small number of the potentially impacted protected species.[547] And the document mentions "certain impacts of oil and gas production facilities and activities at the Elk Hills oil field," which do not encompass the CO_2 capture, compression, transportation and injection activities of this Project.[548] Although the Center for Biological Diversity is aware that a previous oil field operator prepared a Habitat Conservation Plan in 2009 as part of an ITP application necessary to extend a prior permit beyond 2014 and authorize incidental take of species associated with continued oil and gas production activities,[549] there is no publicly available information indicating that plan was finalized.[550]

Because the original Draft EIR does not contain the actual ITP, the Center for Biological Diversity requested from Kern County the ITP noted in other Elk Hills oil field drilling approval documents.[551] The Center received a document in response, ITP number 2081-2014-019-04, issued to California Resources Corporation Elk Hills, LLC. We are including it with our comment submission since this permit must be part of the administrative record. We note that this document we submitted does not appear in the Recirculated Draft EIR's Volume 2

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[544] RDEIR, Vol. 1 at 4.4-23 (take requires an ITP issued under section 2081 or a finding that an ITP issued under the federal Endangered Species Act is consistent with state requirements); *id.* at 4.4-25 (section 10 of the federal Endangered Species Act allows a permit applicant to obtain an ITP through submission of a habitat conservation plan); see also MM 4.4-2 (stating that there may be no incidental take of any protected species without a permit or approved conservation plan).
[545] RDEIR, Vol. 1 at 4.4-36.
[546] RDEIR, Vol. 2, App'x C.2: Conservation Easement Deed – Elk Hills Conservation Area at 2667 *et seq.*; RDEIR, Vol. 2, App'x C.3: Conservation Easement Deed – Elk Hills Conservation Area Map at 2687 *et seq.*
[547] RDEIR, Vol. 2, App'x C.2: Conservation Easement Deed – Elk Hills Conservation Area; RDEIR, Vol. 1 at 4.4-36.
[548] RDEIR, Vol. 2, App'x C.2: Conservation Easement Deed – Elk Hills Conservation Area.
[549] 71 Fed. Reg. 6883.
[550] See 78 Fed. Reg. 39836.
[551] Letter from Center for Biological Diversity to Kern County Planning & Natural Resources Department, *Elk Hills Oilfield Incidental Take Permit* (Jan. 16, 2024); CalGEM, *Notice of Determination, NOD-OG California Resources 072022-201-1* (Aug. 25, 2022).

appendices, and we believe this is an error. ITP 2081-2014-019-04 must be in the record since it is mentioned in Project documents, including the Biological Analysis Report.[552]

Second, ITP 2081-2014-019-04 does not sufficiently include the CTV I Project as a Covered Activity. The ITP explains that the activities covered involve "continued oil and gas related activities and the exploration and development of new wells necessary to enhance recovery and processing of oil and gas reserves."[553] The CTV I Project, in contrast, proposes to capture CO_2 from existing oil field operations, but also "is dependent on the sources permitted for injection into the storage, the ability of the project year by year to obtain CO_2 and inject at the maximum 2,210,000 million tons per year."[554] As noted earlier in this comment letter, additional sources of CO_2 could include DAC, hydrogen, and waste to energy facilities. Moreover, CO_2 compressors, pipelines, injection wells, and other infrastructure are fundamentally different from oil and gas counterparts.

Third, and relatedly, the existing ITP covers only four species—the San Joaquin kit fox, San Joaquin antelope squirrel, giant kangaroo rat, and Tipton kangaroo rat—not the full range of species that could suffer take from the CTV I Project.[555] Even the CDFW—the state's authoritative agency on this issue—reiterated throughout its comment during the Scoping Phase that the existing ITP is insufficient to cover the Project's impacts on protected species.[556] The agency again raised this point in comments on the original Draft EIR, stating that a new ITP and take authorizations are required for candidate species like Crotch's bumble bee.[557] The CDFW issued its opinion based not only on species that the ITP fails to cover, but the deficiency of the existing ITP to address impacts to the four covered species.[558]

It should also be noted that while the current ITP covers incidental take of the TKR resulting from oil and gas production, the Recirculated Draft EIR arbitrarily excludes this species from surveys and consideration of mitigation measures. CRC must therefore obtain a new ITP to cover *all* activities that could result in take of protected species flagged as occurring or potentially occurring in the Project Area. Obtaining ITP(s) covering CTV I Project activities and other species must occur before any construction begins to avoid unlawful take. The County must therefore revise its conclusion that if it "elects in the future to pursue any disturbance . . . that requires additional take authorization," and the Project would obtain a new ITP, per MM

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[552] See, e.g., RDEIR, Vol. 2, App'x C.1: Biological Analysis Report at 2570.
[553] CDFW, ITP No. 2081-2014-019-04, Elk Hills Oil and Gas Field at 2–3 (hereinafter, "ITP Permit 2081"); see also *id.* at 6–10 (listing covered activities and not including CCS).
[554] RDEIR, Vol. 1 at 4.8-24.
[555] ITP Permit 2081 at 11 ("These species and only these species are the 'Covered Species' for the purposes of this ITP.").
[556] RDEIR, Vol. 2, App'x A.2: Comment Letters at 146–65; see also section VI.G, *supra* (noting instances in which the ITP does not cover protected species for the activities proposed).
[557] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1071, CDFW Letter.
[558] See, e.g., RDEIR, Vol. 2, App'x A.2: Comment Letters at 154 (noting that the Project warrants consultation with CDFW and acquisition of a SJKF-specific ITP prior to ground-disturbing activities and for this species, the "existing ITP issued to OXY/CRC does not include the proposed Project as a Covered Activity").

4.4-2. [559] The Recirculated Draft EIR must then be revised to analyze and account for the new ITP.

7. The Recirculated Draft EIR must do more to analyze and mitigate impacts to the Project area's two candidate species.

The Temblor legless lizard (TLL) and Crotch's bumble bee are both Special Status Animal Species with Potential to Occur on Site that could potentially be affected by the Project.[560] The CDFW issued recommended mitigation measures and reminded the County of legal requirements should these species be detected. The Recirculated Draft EIR does not incorporate the proposed mitigations, nor is there indication that the County or Project has followed the legal requirements described.

a. Temblor Legless Lizard

For the TLL, the CDFW notes that habitat loss is the primary threat, and the species is known to occur within and in the vicinity of the Project Area.[561] For this reason, the CDFW concluded that the Project "may have the potential to significantly impact local TLL populations."[562] Despite this, the original and Recirculated Draft EIR propose only "protocol surveys" and pre-disturbance surveys, along with several other generic mitigations associated with other species.[563] The Recirculated Draft EIR ignores the fact that the CDFW points out TLLs "are difficult to detect . . . and are not typically found within dens and/or burrows," making the proposed protocol surveys and avoidance buffers from dens and/or burrows insufficient to "constitute avoidance."[564] The Recirculated Draft EIR offers no evidence to contradict the CDFW, nor does it explain why it ignored these facts.

The CDFW then proposes three mitigation measures: (1) surveys using a CDFW-approved methodology; (2) consultation and development of an avoidance plan; and (3) take authorization prior to commencing ground disturbing activities.[565] The Recirculated Draft EIR ignores each recommendation, as these measures are not reflected in the updated document.

b. Crotch's Bumble Bee

The CDFW is starkly clear in its comment that, for Crotch's bumble bee (CBB), it "does not concur that the Mitigation Measures" in the original Draft EIR "are sufficient to mitigate impacts, to ensure that the Project Area is surveyed sufficiently to determine the presence or absence" of the species, "and to adequately mitigate for the species."[566] The CDFW then recommended three mitigation measures to remedy these deficiencies. The Recirculated Draft

[559] RDEIR, Vol. 1 at 4.4-64 (emphasis added).
[560] See RDEIR, Vol. 1 at Table 4.4-4.
[561] RDEIR, Vol. 2, App'x A.6: Summary of Written Public Comments on original Draft EIR (Dec. 2023) at 1070, CDFW Letter.
[562] *Id.*
[563] *Id.*
[564] *Id.*
[565] *Id.* at 1070–71.
[566] *Id.* at 1071.

EIR, without explanation, does not address the CDFW's concerns, nor does it incorporate any of the proposed changes.

Specifically, the CDFW suggested (1) focused surveys for the CBB and its habitat during the blooming period prior to construction, to be conducted by a qualified biologist and in line with the CDFW's methodology; (2) an avoidance buffer if surveys cannot be completed and consultation with the CDFW to discuss how to avoid take; and (3) take authorization through a new ITP.[567] These measures are reasoned and from an expert agency, and the County must not ignore these important steps to protect this species and its habitat.

H. The Recirculated Draft EIR's Analysis and Mitigation of Land Use Impacts is Inadequate.

1. The Land Use analysis fails to disclose the impacts it purports to mitigate with MM 4.11-7.

The Recirculated Draft EIR introduces a new mitigation measure, MM 4.11-7, that was not part of the original Draft EIR, into the land use section.[568] This measure is added under the analysis of Impact 4.11-2, which considers whether the CTV I Project would "[c]onflict with Any Applicable Land Use Plan, Policy, or Regulation Adopted for the Purpose of Avoiding or Mitigating an Environmental Effect."[569]

MM 4.11-7 limits future CO_2 sources to specific industries, industrial sources, and fossil fuel facilities and types, requires that all sources be located in Kern County, and includes several other conditions regarding the approval and planning processes for such future sources.

CEQA requires an EIR to describe and adopt all feasible mitigation measures to address a project's significant environmental impacts.[570] It requires that "[d]irect and indirect significant effects of the project on the environment shall be *clearly identified and described*, giving due consideration to both the short-term and long-term effects.[571] The discussion of mitigation measures under CEQA "[…] shall identify mitigation measures *for each significant environmental effect identified* in the EIR."[572] MM 4.11-7 fails on all counts.

First, the Recirculated Draft EIR fails to disclose the land-use impact that MM 4.11-7 is set to mitigate. In the discussion under Impact 4.11-2, the Recirculated Draft EIR explains how mitigation measures MM 4.11-1 to 4.11-6 are aimed at avoiding "conformality issues", making sure only specific uses can be approved on the Project site, and avoiding activities that could penetrate the capstone of the storage reservoir or disturb its wildlife protective buffer.[573] MM 4.11-7 is not mentioned in this discussion.

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[567] *Id.* at 1071–72.
[568] RDEIR, Vol. 1 at 4.11-53 to 4.11-54.
[569] RDEIR, Vol. 1 at 4.11-24.
[570] Pub. Resources Code, § 21002; CEQA Guidelines, § 15126.4(a)(1).
[571] CEQA Guidelines, § 15126.2(a) (emphasis added).
[572] CEQA Guidelines, §15126.4(a)(1)(A) (emphasis added).
[573] RDEIR, Vol. 1 at 4.11-50.

The only statement in the Recirculated Draft EIR with some relevance to MM 4.11-7 is where it generally refers to *all* measures together, saying all measures "will provide additional protections, notification for surrounding property owners, and full review of all future sources for compliance with the Zoning Ordinance, General Plan, and CEQA."[574]

But the land use section fails to disclose *what is the impact* MM 4.11-7 will mitigate, or how such impact will be mitigated by it. Because of that omission, it is impossible for the public and decisionmakers to assess MM 4.11-7's effectiveness or even understand the County's logic for proposing it. For example, what is the rationale behind the different requirements the Measure sets for incorporated versus non-incorporated cities? There is no information on this issue in the Recirculated Draft EIR. The general statement above about measures guaranteeing "full review of all future sources for compliance with the Zoning Ordinance, General Plan, and CEQA" is meaningless, as all projects must comply with the law and with general plans, and MM 4.11-7 adds nothing to this requirement.

It is particularly confounding why the new Measure was placed under the land use section. While all the other measures in the section are tied to land use issues and include land use instruments, requiring specific land use entitlements, notices or notations,[575] MM 4.11-7 sets requirements that are more relevant to the CTV I Project's potential impacts on *other* resource areas, mostly GHG emissions and air quality.

The Recirculated Draft EIR must be revised to account for the impacts MM 4.11-7 is set to mitigate, which are not limited to land use impacts, and properly analyze how the Measure will address and mitigate those impacts.

2. MM 4.11-7 is vague and unenforceable.

Under CEQA, proposed mitigation measures must be "fully enforceable" through permit conditions, agreements, or other legally binding instruments.[576] Any proposed mitigation must also provide assurance that such implementation will in fact occur.[577]

Section C.2 of MM 4.11-7 sets the following requirement for CO_2 sources within an incorporated City in Kern County: "the listed use has capture technology for CO_2 that shows compliance with the preparation of an environmental document, with Kern County as a Responsible Agency and not the use of an exemption from CEQA review."

The requirement for capture technology to show "compliance with the preparation of an environmental document" is vague to the point of being meaningless. Technologies, as such, do not require a CEQA process. If the measure intends to condition source approval on the preparation of environmental documents, it should say so explicitly.

[574] RDEIR, Vol. 1 at 4.11-51
[575] RDEIR, Vol. 1 at 4.11-51 to 4.11- 53.
[576] Pub. Resources Code, § 21081.6(b); CEQA Guidelines, §15126.4(a)(2).
[577] *Anderson First Coalition v. City of Anderson* (2005) 130 Cal.App.4th 1173, 1186–87; *Federation of Hillside & Canyon Ass'ns v. City of Los Angeles* (2000) 83 CA4th 1252, 1260.

Similarly, section C.2 of the Measure lists requirements for CO_2 pipelines, stating that any CO_2 pipelines permitted by the California Public Utilities Commission (CPUC) for a common carrier company that requests to connect to CTV I for injection must either "comply with a CUP and EIR" or that "Kern County has participated in the CPUC process and reasonable and feasible mitigation for protection of Kern County communities has been included." Again, the answer to what is "reasonable and feasible mitigation for protection of Kern County communities" is left completely open, without any standards to determine whether this condition is indeed fulfilled.[578] MM 4.11-7 should be revised to include clear and enforceable terms and conditions.

I. The Recirculated Draft EIR Fails to Analyze and Mitigate Cumulatively Considerable Impacts.

Under CEQA, an EIR must discuss significant "cumulative impacts."[579] Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts."[580] A legally adequate cumulative impacts analysis views a particular project over time and in conjunction with other related past, present, and reasonably foreseeable future projects with impacts that might compound or interrelate with those of the project at hand.[581] Such analysis is necessary because "environmental damage often occurs incrementally from a variety of small sources [that] appear insignificant when considered individually, but assume threatening dimensions when considered collectively with other sources with which they interact."[582]

As is the case for all impact categories, a lead agency's threshold findings of significance with regard to cumulative impacts must "be supported by substantial evidence"; and, where found, cumulatively considerable impacts must be adequately mitigated.[583]

CEQA requires an agency to analyze "probable future projects."[584] The courts have found that "[P]rojects that are undergoing environmental review are reasonably probable future projects"[585] and that "any future project where the applicant has devoted significant time and financial resources to prepare for any regulatory review should be considered as probable future projects for the purposes of cumulative impact."[586]

An adequate cumulative impacts analysis and discussion requires a thorough assessment of the incremental significance of the CTV I Project's impacts over time, and in consideration of "other projects causing related impacts."[587] The Recirculated Draft EIR concludes that the CTV I Project will cause potentially significant impacts for a number of impact areas. For some impact

[578] *Gray*, *supra*, 167 Cal.App.4th at 1119.
[579] CEQA Guidelines, § 15130(a).
[580] CEQA Guidelines, § 15355(b).
[581] Pub. Resources Code, § 21083(b)(2); CEQA Guidelines, § 15065(a)(3).
[582] *Communities for a Better Environment*, *supra*, 103 Cal.App.4th at 114.
[583] See CEQA Guidelines, § 15064.7(b).
[584] CEQA Guidelines, § 15130(b)(1)(A).
[585] *Gray, supra,* 167 Cal. App. 4th 1099 at 1127–28.
[586] *Id.* at 1127–28.
[587] CEQA Guidelines, § 15130(a)(1).

areas, the EIR concludes the impact will be cumulatively significant and unavoidable. These areas include aesthetics, agricultural resources, air quality, biological resources, cultural resources, energy, geology and soils, hydrology and water quality, GHG, mineral resources, noise, and utilities and service systems.[588]

However, the Recirculated Draft EIR fails to conduct an appropriate cumulative impacts analysis and support its conclusions with evidence, because it fails to consider the full range of projects that are required in a cumulative impact analysis. Simply declaring a potentially significant cumulative impact is not sufficient, because that declaration by itself neither discloses, nor analyzes, nor guarantees mitigation for, the projected incremental impacts of the project in combination with other projects.

As described above, the project description section of the Recirculated Draft EIR lists under "Cumulative Projects" several projects in the County, and provides nothing more than the name, location, type, acreage, and status of these projects.[589] In doing so, the Recirculated Draft EIR ignores "probable future projects" that must be analyzed in a proper cumulative impacts analysis.

1. The Recirculated Draft EIR must analyze all the projects included in its "cumulative projects" list.

The Recirculated Draft EIR must analyze all the projects included in its "cumulative projects" list in a proper cumulative impacts analysis, and properly assess their potential significant impacts. The Recirculated Draft EIR fails to do so, and most of the projects in the cumulative impacts list are never mentioned again elsewhere in the document. One example of the failure to analyze the cumulative impacts of the Project is the CarbonFrontier CCS Project proposed by Aera (CarbonFrontier Project).

Kern County published the draft EIR for the CarbonFrontier Project in June 2024, at nearly the same time as the Recirculated Draft EIR for CTV I. The CarbonFrontier EIR contemplates a CCS project with over 200,000 acres storage space, located about 9 miles from the CTV I Project site. Similar to CTV I, this project will source CO_2 from an oil field's gas stream, and will have the capacity to receive CO_2 from outside sources.[590] This project is clearly a reasonably probable future project undergoing environmental review. The CarbonFrontier draft EIR briefly mentions CTV I in its short discussion of the Aera merger with CRC, but otherwise dismisses any relationship between the projects, stating that "[t]hey are both included in the respective cumulative impact list in each individual EIR."[591]

But the CarbonFrontier Project is not discussed *anywhere* in the Recirculated Draft EIR beyond its listing as a cumulative project in Table 3-8. Merely listing a project as cumulative

[588] RDEIR, Vol. 1 at 1-13 to 1-15.
[589] RDEIR, Vol. 1 at 3-45 to 3-47 (Table 3-8).
[590] Kern County, *Draft Environmental Impact Report CarbonFrontier CCS Project by Aera Energy, LLC,* (June 2024) at 1-2.
[591] Kern County, *Draft Environmental Impact Report CarbonFrontier CCS Project by Aera Energy, LLC* at 3-16.

does not satisfy the requirement under CEQA to analyze and mitigate cumulative impacts. The Recirculated Draft EIR must be revised to include an analysis of all its cumulative impacts together with the listed projects.

In *Bakersfield Citizens for Local Control v. City of Bakersfield*, 124 Cal. App. 4th 1184, the court found that the cumulative impact analyses for two shopping centers with similar features, a few miles apart from each other, "were fundamentally flawed because they did not recognize that the shopping centers were relevant projects and did not analyze the type and severity of impacts that will result from construction and operation of both projects."[592] While the Recirculated Draft EIR does the first step of including the CarbonFrontier in its cumulative project list, it completely fails to take the required second step—it does not analyze the type and severity of cumulative impacts from CTV I's construction and operation together with the CarbonFrontier Project.

The *Bakersfield* court looked into the potential individual impacts of each shopping center and found that each EIR found an unavoidable adverse impact on ambient air quality. Based on this and a few other impacts, the court concluded that "CEQA compels assessment and disclosure of these combined environmental effects."[593] Similarly, both Draft EIRs for the two CCS projects find significant impacts on air quality and greenhouse gases,[594] but fail to assess and disclose them cumulatively.

2. The Recirculated Draft EIR must analyze cumulative impacts from its probable future sources.

Some of the projects on the cumulative projects list are mentioned as potential CO_2 sources in the "Future Sources – Identification" section in the Recirculated Draft EIR. Analysis of a carbon sequestration project's sources of CO_2 is an essential element of review of cumulative project impacts. An analysis of these sources is necessary not only to understand the impact of their operation together with the CTV I Project, but also in order to give the public and the County decisionmakers information regarding whether and to what extent CTV I will facilitate and incentivize new GHG emissions, rather than reduce existing emissions, whether it will extend the life of existing fossil fuel CO_2-emitting industries, and whether it will create pollution from construction or operation of new facilities. The cumulative analysis fails to include any meaningful discussion of the Project's CO_2 sources.

From the list of cumulative projects, two potential sources are notably absent, and the Recirculated Draft EIR must, at a minimum, analyze them:

a. Hydrogen Plant

The new "Future Sources – identification" section in the Recirculated Draft EIR includes blue hydrogen as a potential source of CO_2 for the CTV I Project.[595] The new section also

[592] *Bakersfield Citizens*, *supra*, 124 Cal. App. 4th at 1214.
[593] *Bakersfield Citizens*, 124 Cal. App. 4th at 1216.
[594] Kern County, *Draft Environmental Impact Report CarbonFrontier CCS Project by Aera Energy, LLC* at 1-2 to 1-16; RDEIR, Vol. 1 at 1-11 to 1-15.
[595] RDEIR, Vol. 1 at 3-13.

describes briefly "[c]ompanies that have publicly indicated their interest in sending CO_2 to the project."[596] Under "Hydrogen", the Recirculated Draft EIR acknowledges that "Lone Cypress Energy Services, LLC, has entered a CDMA to explore development of a clean hydrogen production plant that would produce hydrogen using a steam methane reforming (SMR) process, using natural gas (methane) as feedstock. CO_2 produced as a by-product of the SMR reaction would be captured for underground storage."[597]

The Recirculated Draft EIR states that while an application for the SMR hydrogen project was submitted to the County, and a Notice of Preparation was released in February 2024, the project applicant has withdrawn the application.[598] It provides no other details on the status of the Lone Cypress project, whose status was described as "EIR in Process" in the original Draft EIR, nor does it state the reason for the withdrawal of the application or whether the project proponent intends to re-submit it. According to a letter from CRC and CTV to the EPA, the project is not cancelled, but rather "reassessed."[599]

The Recirculated Draft EIR also fails to disclose that beyond the CDMA it now acknowledges. CTV has announced that it is a direct partner in the Lone Cypress project, noting in a media release that "the CTV [Joint Venture (VR)] has the right to take a majority equity stake in the project, as well as to provide sequestration services for all subsequent Lone Cypress hydrogen projects in California."[600]

Moreover, in an email sent to Kern County Planning Department staff, staff is instructed to hold off publishing the Notice of Preparation (NOP) for the Lone Cypress hydrogen project, because the County intended to imminently release the original Draft EIR for CTV I. The email specifically states the reason for delaying the NOP is that "it will complicate the cumulative projects description" and the County does not have time to change anything.[601] It is clear therefore that but for this delay, the Lone Cypress project should have been analyzed as a cumulative project in the original Draft EIR the County published in December 2023.

Regardless of the specific Lone Cypress application, the Recirculated Draft EIR must analyze the cumulative impacts of a hydrogen project as a CO_2-sending source to the Project. A hydrogen plant is clearly a "reasonably probable future project" under CEQA for cumulative impacts analysis purposes.

As the Recirculated Draft EIR summarily acknowledges, the draft EPA Class VI permit for the CTV I Project identified only two other specific sources beyond the oil field gas as an

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[596] RDEIR, Vol. 1 at 3-14.
[597] RDEIR, Vol. 1 at 3-15.
[598] RDEIR, Vol. 1 at 3-15.
[599] Letter from Travis Hurst, CRC and CTV to David Albright, Groundwater Protection Section (June 17, 2024) at 1.
[600] CRC, *California Resources Corporation Announces Carbon Dioxide Management Agreement For CTV's First Permanent Carbon Storage Project* (Dec. 7, 2022), https://www.crc.com/news/news-details/2022/California-Resources-Corporation-Announces-Carbon-Dioxide-Management-Agreement-For-CTVs-First-Permanent-Carbon-Storage-Project/.
[601] Email from Lorelei Oviatt, Kern County Planning & Natural Resources Dept., *Re: Elk Hills Blue Hydrogen Parcel Map Waiver and CEQA* (Dec. 1, 2023).

initial source—the Lone Cypress Blue Hydrogen and the Avnos DAC project. The 26R storage project draft permits issued by EPA, attached as appendix E.3 to the Recirculated Draft EIR, lists three sources of CO_2 seeking approval: the oil field gas, the Lone Cypress hydrogen plant, and the Avnos DAC project. The draft permits state they are to be located within the Elk Hills oil field.[602]

On July 10, 2024, the EPA published a revised versions of the draft permits for comments, noting the revisions include the removal of references to the Avnos Direct Air Capture Facility and Lone Cypress Hydrogen Facility as proposed carbon dioxide sources.[603]

The Recirculated Draft EIR argues that an EPA action on draft permits "[…] does not mean the projects are approved,"[604] but fails to account for the significance of the EPA permit process for a proper cumulative impacts analysis.

EPA is the primary regulatory authority for Class VI injection permits, which are required for CO_2 injection into underground subsurface rock formations, as the Project intends to do. In other words, an EPA permit is an indispensable condition for the Project to move forward. And the permits, in their current draft form, allow injection of CO_2 from only those three sources. The draft permits make clear that the Project proponent may request to inject CO_2 from other sources, but this will require further application, review, and approval by EPA, as described in Section N of the permits.[605] Section N lists the conditions for approval of *additional* emission sources, a process which includes disclosure of the CO_2 stream, description of the source industry, evaluation of potential air pollution impacts, and public notice, among other things.

The draft permit requirements mean that detailed information is already known regarding the oil field gas, the hydrogen plant, and the DAC project, and can be used in the cumulative impacts analysis. EPA is clear that its process to issue the original draft permits included "a thorough technical review of all information submitted by CTV in its permit application, as well as the operational standards, monitoring requirements, and existing geologic setting" that was sufficient for the EPA to make a determination under the Safe Drinking Water Act.[606]

Moreover, the Project evidently relies on sources beyond the oil field gas initial source to send CO_2 to the Project *almost immediately* after it begins operation: The Recirculated Draft EIR's analysis discloses that at a maximum, the oil field's CO_2 will add up to 203,485 tons per year (tpy) of captured CO_2.[607] But its GHG analysis projects over 300,000 tons of CO_2 to be injected by its second year—clearly from approved sources beyond the initial source.

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[602] RDEIR, Vol. 2, App'x E.3 – 26R Storage Project Draft Permits. The same language repeats in all four permit drafts included in the appendix.
[603] EPA, *Public Comments Sought on Class VI UIC Injection Well Carbon Storage Draft Permits* (July 2024) at 1.
[604] RDEIR, Vol. 1 at 3-14.
[605] RDEIR, Vol. 2, App'x E.3 – 26R Storage Project Draft Permits.
[606] EPA, *Public Notice of Intent to Issue a Class VI Underground Injection Control Permit for Carbon TerraVault JV Storage Company Sub 1, LLC* (Dec. 2023) at 1.
[607] RDEIR, Vol. 1 at 3-2.

A hydrogen project, whether it is the Lone Cypress project or a different but substantially similar hydrogen project, is clearly a "reasonably probable future project" given the contents of the EPA draft permits and the applicant's predictions for the Project's capture of CO_2. Regardless of whether the hydrogen project is part of the latest draft permits or not, the SMR hydrogen plant also clearly falls under what the courts describe as a "future project where the applicant has devoted significant time and financial resources to prepare for *any* regulatory review."[608] The EPA regulatory review requires significant time and resources, and the hydrogen project that is part of that ongoing review must be considered a probable future project.

It should be noted that in their letter to EPA, CRC and CTV are clear that this removal of sources is happening in the "short-term." They are also clear that "even if the Lone Cypress and/or Avnos project does not proceed, CRC expects that over time sources of CO_2 for the 26R UIC permits will likely include hydrogen and direct air capture facilities (among other potential future sources of CO_2)."[609]

It is also evident that CRC contemplates the development of blue hydrogen plants as part of its operation. In a letter to CARB, CRC urges the agency to include in its Low Carbon Fuel Standard (LCFS) amendments hydrogen plants that will rely on CCS to capture GHG emissions, stressing that should the agency act differently, it will "ultimately frustrate the deployment of low carbon hydrogen projects in California."[610]

In addition, the Recirculated Draft EIR discloses that the Project is already undergoing another regulatory review process: CARB review under the CCS Protocol adopted under the LCFS.[611] The review, which is required for the CTV I Project to qualify for LCFS credits, is highly technical and complex. Project proponents are required to provide detailed, third-party verified information regarding the geological CO_2 sequestration, and show they adhere to the Protocol and qualify for certification that the CO_2 will be retained in the ground. As is clear from the Recirculated Draft EIR, CTV I already filed at least 13 reports with CARB to address the permanence requirements related to site characteristics, risk assessment, plume extent evaluation, testing and monitoring, well operation, post-injection site care, and more.[612]

The reports the Project proponent filed with CARB clearly identify a hydrogen plant as the main source for CO_2, stating: "[t]he anthropogenic CO2 will be sourced from an onsite blue hydrogen plant (up to 200,000 tonnes per annum) with additional potential CO_2 from the Elk Hills 550 MW natural gas combined cycle power plant, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area."[613] This CARB process, including the promise

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[608] *Gray v. Cnty. of Madera*, (2008) 167 Cal. App. 4th 1099, 1127–28 (emphasis added).
[609] Letter from Travis Hurst, CRC and CTV, to David Albright, Groundwater Protection Section (June 17, 2024) at 1–2.
[610] CRC letter to CARB, *RE: Proposed 2024 Low Carbon Fuel Standard Amendments* (Feb. 20, 2024) at 3. See also CRC's application to CARB under its CCS Protocol for LCFS certification.
[611] RDEIR, Vol. 1 at 4.6-5 to 4.6-6.
[612] RDEIR, Vol. 1 at 4.6-6; RDEIR, Vol. 2, App'x F: CARB LCFS Report #1, Site Based Risk Assessment at 1.
[613] CARB LCFS Report #3, *Storage Complex Delineation and Corrective Action Plan, CTV Elk Hills Oil Field (EHOF)* at 6-7.

of an SMR hydrogen plant, constitutes a regulatory review that the applicant devoted significant time and resources to prepare.

It should be noted that the CARB reports do not identify a specific hydrogen project, but "a blue hydrogen plant." Since the industrial process (methane steam reforming) is known, and the volume of production is disclosed in both regulatory processes,[614] the Recirculated Draft EIR must disclose and analyze the potential cumulative impacts, including impacts from co-pollutants, impacts on water resources, and safety hazards resulting from the anticipated "blue hydrogen" facility.

b. DAC Project

Similar to the hydrogen project, the Avnos DAC project is one of the three sources included in CRC's application to the EPA for a Class VI injection well permit and in the EPA's draft permits.[615] It was also removed in the recent permit revisions.[616] Direct air capture is also on the list of future Project sources added to the Recirculated Draft EIR.[617]

In its short discussion of the DAC project, the Recirculated Draft EIR states that "[i]t is unknown if there is an existing CDMA or other commercial agreement between CRC and Avnos. The applicant notes that CTV I is in preliminary commercial discussions with Avnos, Inc., to construct a DAC facility that would be designed to intake and process atmospheric air to separate out CO2."[618] On its face, the statement "[i]t is unknown if there is an existing CDMA or other commercial agreement" lacks credibility, since CRC could easily provide any information to the County regarding the existence of such agreements, much as CRC has provided all the other information it has provided to the County—including the statement in the sentence following.

Beyond that, this statement downplays the connections between the Project proponent and the DAC project as well as the DAC project status. First, in its 2023 operations updates, CTV describes the California DAC Hub as being "led by CTV's subsidiary CTV Direct, LLC" and states it was selected to receive approximately $12 million in DOE funding.[619] CTV I also describes itself as responsible for assembling "a consortium of organizations across industry, technology, academia, national labs, community, government, and labor, to pursue U.S. Department of Energy (DOE) funding under its Regional Direct Air Capture (DAC) Hubs

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[614] Up to 200,000 tonnes per annum per App'x E.2 – *U.S. Environmental Protection Agency Class VI Underground Injection Control (UIC) Permit Application Narratives for the Elk Hills 26R Storage Project and the A1A2 Storage Project* (Attachment C).
[615] RDEIR, Vol. 2, App'x E.3 – 26R Storage Project Draft Permits. The same language repeats in all four permit drafts included in the appendix.
[616] EPA, *Public Comments Sought on Class VI UIC Injection Well Carbon Storage Draft Permits* (July 2024) at 1.
[617] RDEIR, Vol. 1 at 3-13.
[618] RDEIR, Vol. 1 at 3-15.
[619] Business Wire, *Carbon TerraVault Provides 2023 Update* (Feb. 27, 2024), https://www.businesswire.com/news/home/20240227366330/en/Carbon-TerraVault-Provides-2023-Update.

Initiative to create the California DAC Hub, the state's first full-scale DAC plus storage (DAC+S) network of regional DAC+S hubs."[620]

In addition, in a quarterly report to the CPUC from January 31, 2024, SoCalGas discloses that it is a member of the California Direct Air Capture Hub Consortium working toward the DAC project in Kern County and that the consortium was awarded an $11.8 million grant from DOE. This report further states that the DAC facility's project manager "is currently in contract negotiations and expects to finalize the negotiation in early 2024, allowing for an expected project kickoff thereafter."[621]

Also similar to the hydrogen project, a DAC project is listed as a potential source in the reports CTV I filed with CARB under the CCS Protocol.[622]

The DAC project is not only a "reasonably probable future project," but also a "future project where the applicant has devoted significant time and financial resources to prepare for any regulatory review."[623] Its impacts must be analyzed cumulatively in order for the Recirculated Draft EIR to be legally and informationally sufficient.

The result of the Recirculated Draft EIR's failure to properly account for cumulative projects and their impacts is that its cumulative impacts analysis is deeply flawed, lacking any analysis of the environmental impacts expected to be produced by probable future projects, or an analysis of whether the impacts are cumulatively considerable.[624]

It is evident that the Project is completely dependent on its sources. The Recirculated Draft EIR states that "[t]he life of the project is dependent on the sources permitted for injection into the storage" and on "the ability of the project year by year to obtain CO_2 and inject at the maximum 2,210,000 million tons per year."[625] The Recirculated Draft EIR should therefore include a cumulative impacts analysis of all the projects listed in Table 3-8, and in particular of potential CO_2 sources it lists as cumulative projects.[626]

Finally, cumulative impacts analysis cannot merely be a cursory description of probable future projects, without any analysis. The description and analysis of cumulative impacts should reflect their severity and the likelihood of their occurrence.[627] While this analysis does not have to reflect the same level of detail as the primary analysis of the Project's impacts, it still must be

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[620] CRC, *California DAC Hub*, https://www.crc.com/carbon-terravault/projects/california-dac-hub/default.aspx (last accessed Mar. 1, 2024).
[621] SoCalGas, *Quarterly Report on Status of Infrastructure Investment and Jobs Act (IIJA), Inflation Reduction Act (IRA), or Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS) Projects Pursuant to Resolution E-5254* (Jan. 31, 2024) at 2.
[622] CARB LCFS Report #3, *Storage Complex Delineation and Corrective Action Plan, CTV Elk Hills Oil Field (EHOF)* at 6-7
[623] *Gray*, 167 Cal. App. 4th at 1127–28 (emphasis added).
[624] CEQA Guidelines, § 15065(a)(3).
[625] RDEIR, Vol. 1 at 4.8-24.
[626] RDEIR, Vol. 1 at 3-45.
[627] CEQA Guidelines, §15130(b); *City of Long Beach v. Los Angeles Unified Sch. Dist.* (2009) 176 Cal.App.4th 889.

reasonable and show a good faith effort to disclose the impacts.[628] As described under each impact area section in these comments, the Recirculated Draft EIR does not provide any meaningful analysis of the cumulative impacts attributable to the probable future projects, and ignores even the projects it lists as cumulative projects in Table 3-8.

The courts made clear that lead agencies have a duty to approach the issue of cumulative impact analysis in a way that will "afford the fullest possible protection to the environment within the reasonable scope of their language."[629]

The Recirculated Draft EIR must be revised to fully account for the cumulative impacts attributable to *all* of the CTV I Project's cumulative projects, including, but not limited to, the CarbonFrontier Project and the hydrogen and DAC CO_2 projects.

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For the reasons set forth above, we urge the County to re-do its analysis, prepare and circulate a revised Draft EIR, and, ultimately, reject the CTV I Project.

We reserve the right to identify new issues, provide additional information, and propose additional mitigation measures during the County's ongoing decisionmaking process for the CTV I Project.

If you have any questions about the foregoing comments, you may reach out to any of us directly or contact the Earthjustice contacts listed below, who helped prepare this submission.

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[628] *Citizens for Open Gov't v. City of Lodi* (2012) 205 Cal.App.4th 296, 320.
[629] San Franciscans for Reasonable Growth v. City & Cnty. of San Francisco, 151 Cal. App. 3d 61, 74, 198 Cal. Rptr. 634, 640 (Ct. App. 1984)

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ATTACHMENT A

Comment on the Air Quality and Greenhouse Gas (GHG) Analysis Provided in the Draft Environmental Impact Report (SCH# 2022030180) for the Carbon TerraVault 1 (CTV1) Project in Kern County, California Proposed by California Resources Corporation, December 2023

by

Dr. Ranajit (Ron) Sahu[1]

I provide the following technical comments based on my review of the air quality and GHG analyses provided for the proposed CTV1 project in the DEIR. The lead agency for the EIR is Kern County's Planning and Natural Resources Department (Mr. Keith Alvidrez).

The figure below, taken from the DEIR shows the two dis-jointed parcels (at the surface) where the proposed project will be implemented.

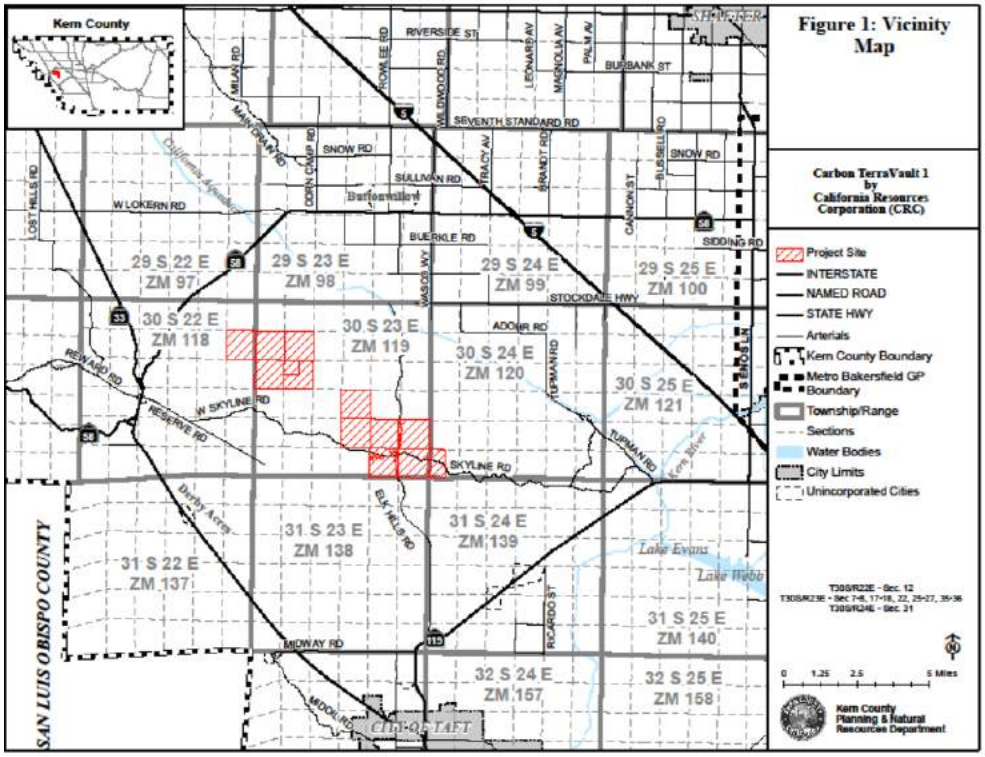


Figure 1: Regional Vicinity Map

[1] Resume provided in Attachment A.

My comments are based on information provided in the body of the DEIR (in Volume 1) and Appendix B (in Volume 2, specifically the report prepared by Trinity Consultants[2]) which contains the supporting information on the air quality and GHG analyses. My comments point out the deficiencies in the analysis, including the lack of support or rationale for critical inputs which should be addressed. Given the lack of publicly available information on the proposed project, I am unable to provide an independent, alternate set of analyses and results.

Comment 0 – Inconsistent Description of the Proposed Project

Page 1-1 (Introduction) and page 3-1 (Project Description) of the DEIR state:

> The Carbon TerraVault I (Kern County) Project (CTV I) proposed by California Resources Corporation (CRC, or project proponent) would request the approval of multiple Conditional Use Permits (CUPs)…for the construction and operation of an approximately 9,130-acre carbon capture and storage (CCS) facility with related capture facilities and pipeline for the initial source and request associated Zone Change Case (ZCC) No. 5, Map 119 and ZCC No. 4, Map 120 from A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 6,160 acres."[3]

Appendix B.1 of the DEIR states that:

> "…[T]he Project will involve a 5,332-acre carbon capture and sequestration field, associated sequestration injection wells and related improvements for storage of Carbon Dioxide (CO_2)."[4]

Yet, later in the same document, it states that:

> "[T]he Carbon TerraVault 1 Carbon Capture and Sequestration Project is consideration of the approval of multiple Conditional Use Permits (CUP) (CUP No. 13, Map no. 118, CUP No. 5, Map 119, CUP No. 3, Map 120) and related changes in zoning designations (ZCC No.5, Map No.118, ZCC No. 5, Map 119, ZCC No. 4, Map 120 for the construction and operation of a 7,385.67 acre carbon capture and storage (CCS) facility, with associated Class VI Underground Injection Control (UIC) wells, 13 miles of facility pipeline for capture from the pre-combustion gas and related infrastructure improvements for the capture, transfer, and storage of CO_2."[5]

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[2] DEIR, Appendix B.1. Air Quality Impact Analysis, May 2023 (revised November 2023), prepared by Trinity Consultants.

[3] DEIR, pages 1-1, 3-1.

[4] DEIR, Appendix B.1, p. 1-1. (emphasis added)

[5] DEIR, Appendix B.1, Section 2.2. (emphasis added)

Please clarify the discrepancies between the three very different acreages noted above.

Comment 1 – Missing Details and Energy/Air Quality Impacts of the Carbon Capture System

The DEIR contains no engineering information about specific design and/or details regarding the operations of the carbon capture (CC) system that is/will be implemented at the Elk Hills power plant or at the existing cryogenic and fractionation natural gas plant (CGP-1) facility (or any other sources of GHG) before those emissions are then managed, ultimately being injected into geologic formations for sequestration.

As an example, while CC systems naturally involve additional equipment such a blowers and ductwork, which incur energy penalties in order to operate, the DEIR does not provide the details supporting the approximately 31 MW per year[6] of energy it estimates that will be needed to operate the CC facilities and associated equipment.

In addition, while the DEIR notes that the energy/power needed to operate the CC facilities would be sourced from the Elk Hills Power Plant, it does not discuss how this additional power generation will change the load factor and other operating characteristics of the power plant. The DEIR, in summary fashion at Appendix B.1, simply states that "…[T]he Elk Hills Power Plant provides about one third of its power to the oilfield for operations and the remainder is distributed to the California power grid via the Pacific Gas and Electric (PG&E) substation in Buttonwillow." It does not discuss how the additional power/energy needed by the proposed CC facilities would be accommodated by the Elk Hills power plant. I note that the DEIR simply assumes that the power plant will continue to operate at an annual (and constant) capacity factor of 93%[7] for every single year of the 30 year duration of the proposed project. The justification for this capacity factor and whether or not it includes the additional energy needed for the CC system is not clear. That should be clarified.

In addition, given that the expected duration of the proposed project is 30+ years, it is presumed that the Elk Hills Power Plant will need to operate for the next three decades to support the project, whether or not the plant would have continued to run for all this additional time into the future without the project. As it stands, the Elk Hills Power Plant is approximately 20 years old already. So, that means the proposed project would require the power plant to operate till it is 50+ years old. Without significant additional investments to extend the life of the power plant, it is likely that the Elk Hills power plant would have shut down but for the proposed project. The DEIR

[6] DEIR, p. 4.6-15.

[7] DEIR, Appendix B, tables on pdf pages 310-311.

should address whether or not the proposed project enables the life extension of the Elk Hills power plant and the impacts of any such extension.

Comment 2 – Cursory and Missing Aspects of GHG Leakage

There is little to no detail on the leakage of GHGs, including but not limited to the various types of potential leakage of CO_2 from different aspects of the entire project.

While the DEIR makes a gross assumption that the GHG capture will be 95%,[8] it is not clear if, therefore, the remaining 5% uncaptured GHG is presumed to be an annual leakage level for the duration of the project. If so, what specifically is included in this 5% leakage is not discussed. That should be clarified.

It appears however, that, at best, this uncaptured GHG might include losses during capture of the power plant's exhaust as well as certain fugitive losses in processing the exhaust waste gases containing GHG to and through the amine system, followed by its conveyance to the injection wells. Importantly, three additional potential loss mechanisms and their GHG losses (and associated leakage) do not appear to have been addressed or quantified:

(i) GHG losses associated with ruptures or failures of the additional new pipelines or pipeline components proposed as part of the project. Given the large geographic extent of CTV1, including the gathering and injection infrastructure and given the assumed three decades of operation, such failures are quite likely;

(ii) GHG losses associated with the maintenance of equipment, including "blowdown" or similarly necessary emissions in order to allow for proper preventive maintenance. Pipeline maintenance typically requires evacuation of pipeline sections in order to safely effect such maintenance. Such evacuation necessitates "blowdown" of the gas contained in the pipeline sections. Unless otherwise gathered or captured – which is not discussed in the DEIR – these events can result in emissions of waste gases, containing GHG and other pollutants to the atmosphere; and

(iii) GHG losses from the geologic formation itself due to the injected GHG/CO_2.[9] While the DEIR generally admits that there could be potentially significant leakage[10], the DEIR does not provide any details including the probabilities of such leakage, the circumstances

[8] Curiously, in Section 4.11 of Appendix B.1, this 95% capture is at the amine units. Why that is the case is not clear. The DEIR should clarify.

[9] DEIR, Appendix B.1, Section 2.2 notes that annually 1.5 million metric tons of CO_2 will be injected, with an overall total project injection of 48 million metric tons. This is roughly a 32 year time period.

[10] For example, DEIR at p. 4.8-26.

under which such leakage may occur, or any quantification of the leakage.

The DEIR does include a few monitoring wells but the logic of their placement (including depths) in the various locations and how just the small number of proposed monitoring wells will provide enough assurance that GHG once injected will not migrated from the intended injected formation, is not provided and is not supported by evidence. This un-sequestered GHG migration may not just be towards the surface (i.e., vertically upwards) but also laterally and even downwards from the formation, eventually manifesting themselves as leakage to the surface. While the timing of this subsurface leakage mechanisms may not occur just during the presumed thirty or so year project period (and its GHG accounting of the benefits of sequestration), that does not mean that leakage after (or long after) the thirty or so year time period should simply be assumed to be zero, with little to no support and little to no verification.

* * * * *

The remainder of my comments address specifics about the air quality and GHG analyses presented in the DEIR. For air quality, I focus mainly on the discussion provided in Chapter 4.3 (specifically Sections 4.3.4 and 4.3.5) and Appendix B (specifically Appendix B.1 – the Trinity Consultants report, from which much of the analysis in the body of the DEIR is drawn from), including certain mitigation measured proposed in the DEIR. For GHG, I have reviewed the analysis presented in Section 4.8 of the DEIR and also in Appendix B. I have also reviewed Appendix F in Volume 2 relating to a site-specific risk assessment.

Comment 3 – Air Quality Emissions Estimates

It is crucial that an air quality analysis fully support the assumptions underlying its emissions estimates, as those assumptions and resulting emissions estimates ultimately affect the DEIR's assessment of project impacts and feasible mitigation.

This is true for all types of air pollutants (i.e., criteria pollutants, air toxics or hazardous air pollutants, and GHG) and from all potential emissions generating sources and activities of the proposed project, including both construction and operational phases.

While it is customary in conducting EIR-type air quality analyses to rely on "standard" models to develop emission estimates as has been done in this DEIR,[11] those models typically only have emission factors (i.e., mass of emissions of pollutant X from a source Y – like piece of fuel-burning

[11] DEIR, Section 4.3.4.

equipment, for example). That such standard models have been used in the present instance is confirmed by the DEIR:

> "[T]he construction and operational emissions were estimated from several emissions models and associated spreadsheet calculations, depending on the source type and data availability. The primary emissions models used included CARB's on-road vehicle emission factor model (EMFAC) version 2021 and the California Emissions Estimator Model (CalEEMod) version 2021.1.13." In addition, the DEIR states that "[T]he capture facilities (new amine unit valve) fugitive emissions have been quantified using the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities…"[12]

The user of the model or the analyst has to input the corresponding activity factor (i.e., how many and what types of equipment, of what sizes, hours of usage, etc.) in order to run the model and obtain estimates of the mass of emissions (i.e., pounds or tons) from those activities over the desired time period (hours, days, weeks, year, etc.).

An accurate analysis and robust evaluation of impacts is especially important here given that the proposed project will be located in an area that is already non-attainment for several criteria pollutants including: ozone (Federal and State); PM_{10} (State); and $PM_{2.5}$ (Federal and State).[13] I should note also that, for $PM_{2.5}$, the EPA has now proposed to make the primary (i.e., health based) annual National Ambient Air Quality Standard (NAAQS) more stringent from its current level of 12 ug/m^3 to a range between 9 – 10 ug/m^3, reflecting the current science on adverse health impacts of this zero-threshold air pollutant.[14] The adoption of the stricter standard means that the air quality in the area is even more unhealthy than understood previously and even further from attaining the health-based NAAQS than acknowledged in the DEIR.

Comment 3.1 – Emission Factors and Errors

I should note for the record that just because the "standard" models incorporate emission factors for various pollutants and for various types of equipment and activities, that does not mean that those emission factors do, in fact, accurately or conservatively represent the emissions of the respective pollutants from specific equipment and specific activities that are part of the project.

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[12] *Id.*

[13] DEIR, Table 4.3-2.

[14] https://www.epa.gov/newsreleases/epa-proposes-strengthen-air-quality-standards-protect-public-harmful-effects-soot

First, there are issues of representativeness of the emission factors, especially as they apply to not just new equipment but also to older equipment and the inevitable deterioration of their emissions (including deterioration of any air pollution controls) over time. This specifically applies to the emission factors that are included as part of the "standard" models used to develop emission estimates as noted prior.

Second, there are always issues of precision and error in emission factors (and activity factors, which I discuss later) and the resultant emissions estimates. The emissions estimates in the DEIR in many instances provide values to many significant digits (i.e., implying greater – and false – precision than warranted), thereby misleading the reader as to the accuracy of the air quality emissions estimated. The DEIR contains no estimates of the errors in any of the calculations. In fact, a proper analysis should provide some guidance of the error (or the range) of the emissions as opposed to misleadingly precise estimates for the reader. The DEIR fails completely on this score. To meaningfully inform the public and decision makers, the DEIR should quantify and disclose uncertainties in the emissions estimates.

Comment 3.2 – "Existing" Air Quality Information is Dated And May Not Be Representative

Section 3.2 of Appendix B.1 summarizes "existing" air quality – i.e., ambient monitoring concentrations of several pollutants. Yet, even though the report in Appendix B.1 was revised in November 2023, this "existing" ambient data is only provided for the years 2019 through 2021. Further, the description misleadingly states that these are "the last three years." Clearly that is not the case since no data is provided for 2022. There is also no mention of why 2022 data could not have been reported. That should be fixed. Notably, quality-assured data from 2022 is readily available.[15]

I also note that this "existing" three-year time period of 2019-2021 was substantially impacted by COVID-19 for the years 2020 and 2021. As such, due to changes in economic activities including transportation patterns, and many other factors, it is not assumable, without further discussion, that this impacted three-year period is representative of "existing" air quality. I suggest that a broader time period, say, 5 or even more years, including 2022, be included to describe existing air quality, with comments, as necessary, on any patterns in the data.

Comment 3.3 – None of the Assumptions Made For Estimating Project-Related Emissions Are Supported by Any Justification and/or Rationale

[15] See, https://www.arb.ca.gov/aqmis2/display.php?param=OZONE&units=007&statistic=DAVG&year=2022&mon=12&day=31&county_name=15-Kern&basin=--AIR+BASIN--&latitude=--PART+OF+STATE--&report=7DAY&order=basin%2Ccounty_name%2Cs.name&submit=Retrieve+Data&ptype=aqd&std15=

I will provide examples of these unsupported assumptions in this comment. I also note, that in each instance, there is no verification of any of these assumptions proposed in the DEIR either.

(i) for short-term construction emissions, it is assumed that the construction schedule will be 11 days per well pad, 18 days per well, 2 years for the capture facilities, and 1 year for the pipelines (later noted as 220 days). None of these timelines are supported.

Specifically, Table 4-12 in Appendix B.1 shows the details of the wells to be constructed/repurposed as part of the project. It is excerpted below for easy reference.

Table 4-12. Total Emissions on a Per Well Basis

Well Name	Description	Depth (ft)	Emissions (Tons)
26R Reservoir			
363C-27R	Injector	6290	4.55
353XC-35R (new)	Injector	6390	4.55
373-35R (new)	Injector	7010	5.36
345C-35R (new)	Injector	5690	3.98
341-27R	Plume monitoring	6981	4.55
328-25R	Plume monitoring	5268	3.98
376-36R	Plume monitoring	5832	3.98
355X-26R	Above-zone monitoring	4063	2.35
USDW Monitoring (new)	USDW monitoring	400	1.28
A1/A2 Reservoir			
355-7R	Injector	8387	6.17
357-7R	Injector	8420	6.17
353A-7R	Plume monitoring	8773	6.17
335X-7R	Plume monitoring	8737	6.17
327-7R-RD1	Above-Zone monitoring	3782	2.03
345-7R	A3+ Monitoring	8904	6.17
388X-7R	A3+ Monitoring	8800	6.17
342-17R	A3+ Monitoring	8844	6.17
USDW Monitoring (new)	USDW monitoring	740	1.28
Total			**81.08**

I note that the well depths, excluding the groundwater monitoring wells, in Table 4.12 range from as low as 3782 ft to as high as 8904 feet. Given this wide range of well depths and many other depths noted in Table 4-12, it makes no sense to presume that there will be 18 days required to construct each well. If the intent is to presume that 18 days is the "average" for all wells/various depths noted above, that should be justified. Clearly, the wells in the A1/A2 reservoir will be drilled to deeper depths as compared to the wells in the 26R reservoir. Since they are not expected to be drilled all at once, the construction schedule for the wells should be provided in greater detail, along with supported construction durations.

In addition, it is not clear how the well depths in Table 4-12 were so precisely estimated, right down to the last foot (for example, 6981 feet, 4063 feet, etc.). Please provide the rationale since the depths will affect construction timelines.

(ii) Section 4.2.1 of Appendix B.1 contains a number of mobile source activity assumptions. These include: a 40-mile trip distance; 160 average daily trips (ADTs) for workers during construction; 32 ADTs by 1-ton trucks and 20 ADTs using 5-ton trucks, in addition to 8 water trucks; 16 ADTs by workers and 2 ADTs by vendors during well pad construction; and 12 ADTs by workers and 10 ADTs by vendors during well construction. There is no justification provided for any of these assumptions. Thus, the emission estimation approach is nothing more than an algebraic exercise. As a simple example, it is not clear why there should be a 40-mile trip distance for both workers and vendors. Also, since there is no description of the work that will be done during construction of the well pad and the well, there is no context for understanding if the assumed numbers of workers/vendors, as well as equipment proposed, makes any sense.

These types of assumptions should be supported by actual data that is undoubtedly available to the project proponent since these are not the first well pads nor first wells that are going to be drilled in this area.

(iii) Similarly, there are numerous assumptions about the types, numbers, and operating hours of various construction equipment that will be used in developing the construction emissions. These are inputs to the emissions calculations in the standard models used to develop those estimated. I have excerpted Tables 4-3 through 4-6 from Appendix B.1 below that contain these assumptions.

Table 4-3. Facilities Construction Equipment

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Hydro Crane	Cranes	5	1968.75	3.8
ForkLift	Forklifts	7	1968.75	3.8
Excavator	Excavators	1	1968.75	3.8
Backhoe	Tractors/Loaders/Backhoes	4	1968.75	3.8
Air Compressor	Air Compressors	20	246.09	0.5
Crane	Cranes	3	246.09	0.5
Loader	Rubber Tired Loader	3	246.09	0.5
Dozer	Rubber Tired Dozers	1	1968.75	3.8
Dump Truck	Off-Highway Trucks	2	1968.75	3.8
Welding Truck	Welders	8	1968.75	3.8

Table 4-4. Pipeline Construction Equipment

Equipment	CalEEMod Equipment Designation	Quantity	Average Daily Operating Hours
Crane	Cranes	3	5.0
Boom Truck	Other Construction Equipment	3	5.0
Crane	Cranes	3	2.5
Side Boom	Other Construction Equipment	6	5.0
Bending Machine	Other Material Handling Equipment	1	2.5
Air Compressor	Air Compressors	4	5.0
Air Compressor	Air Compressors	1	2.5
Welding Machines	Welders	8	5.0
DitchWitch	Off-Highway Trucks	1	2.5
Vacuum Truck	Other Construction Equipment	2	2.5

Table 4-5. Well Pad Construction Equipment (Per Well)

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Grader	Graders	1	16	1.5
Front Loader	Tractors/Loaders/Backhoes	1	40	3.6
Excavator	Excavators	1	32	2.9
Water Truck	Other Construction Equipment	1	40	3.6

Table 4-6. Well Drilling Construction Equipment (Per Well)

Equipment	CalEEMod Equipment Designation	Quantity	Total Operating Hours per	Average Daily Operating Hours
Forklift	Forklifts	1	72.0	4.0
Drilling Rig Motor	Bore/Drill Rigs	1	275.4	15.3
Drilling Rig Motor	Bore/Drill Rigs	1	322.2	17.9
Drilling Rig Motor	Bore/Drill Rigs	1	216.0	12.0
Small Generator	Generator Sets	1	8.0	0.4
Light Tower	Generator Sets	2	216.0	12.0
Water Truck	Other Construction Equipment	1	144.0	8.0
Vacuum Truck	Other Construction Equipment	1	432.0	24.0

The DEIR/Appendix B.1 should provide justifications for the equipment type, the numbers of each equipment, and the expected operating hours in each instance. It is also clear that the operating hours are provided with a high degree of precision, with no rationale. For example, 3.8 hours of operation per day for several types of equipment (along with the equally precise annual operating hours (246.09, 1968.75), in Table 4-3. What is the basis of such precision? Similar comments also apply to the other tables above.

(iv) Long-term, i.e., operational emissions are discussed in Section 4.2.2 of the Appendix B.1 for fugitive (dust) emissions (Section 4.2.2.1) and mobile sources (Section 4.2.2.2). However, fugitive dust emissions are simply not quantified. Instead it is noted that these are "…not expected to present a substantial source of fugitive dust (PM_{10}) emissions…" What is the basis for this conclusionary assertion, with no supporting data or calculations?

In addition, the DEIR presumes that the main source of PM_{10} emissions would be from vehicular traffic associated with the project.[16] While this is true, PM_{10} also results from soil disturbance associated with land grading, including stockpiling of soils and also from the storage of other erodible construction materials.

Further, the DEIR does not address fugitive $PM_{2.5}$, for which the area is non-attainment at present and likely to be even more so when the NAAQS for $PM_{2.5}$ is revised downward per EPA's current proposed, as noted prior.

(v) As for mobile source exhaust emissions during operations, like in the case of construction, the DEIR/Appendix B.1 makes numerous unsupported assumptions, with the exception of a reference to a traffic study estimating 20 ADTs from workers. However, other assumptions such as: the 40-mile trip distance; the assumption for 10 additional workers; the complete lack of any vendor-related trips or emissions are not justified or

[16] DEIR, p. 4.3-65.

supported at all. The DEIR should provide that support or revise as needed. The DEIR should provide the justification for why no vendor support would be needed as operational support for the various injection and monitoring wells.

(vi) In addition to the fugitive and mobile source emissions during operations, the only stationary source emissions included in the analysis are from fugitives from component leaks from the two new amine units that will be installed are estimated (in Table 4-11 of Appendix B.1) using the previously mentioned Implelentation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. However, the applicability of these estimates for "petroleum facilities" to the amine units is not clear. Please provide the justification. Also, please clarify what fractions of the components of each type are expected to be "leakers" at different levels of assumed leakage, i.e., 50 ppm, 100 ppm, 250 ppm, 500 ppm, 1000 ppm, 10,000 ppm, etc. And, how these leakers have been included (or not) in the current calculations.

(vii) Previously, I have excerpted Table 4-12 showing the depths of the 18 new wells that will be drilled, for the various purposes shown in that table. In connection with the drilling schedule, I have also provided a comment about the precisions of the well depths noted in Table 4-12. In addition, I have additional comments/questions:

- First, I note that the DEIR provided no justification provided for the well depths for just/only the two above-zone monitoring wells (i.e., one for each reservoir) noted in that table.
- Second, the DEIR provides no justification (geologic or otherwise) for the depths of these two monitoring wells, that are approximately 2000 feet or higher than the reservoirs themselves.
- Third, the DEIR does not state how such a single monitoring well will be placed exactly where some leakage might manifest itself, given the vast area/acreages in each reservoir.
- Finally, the DEIR does not discuss or address potential leakages that may occur from the formation in directions other than vertically, such as initially laterally or even downward from the formations, later finding their way to the surface. The DEIR does not address how these potential leakage paths will be monitored.

In sum, it appears that, at least as far as the monitoring of the injection/sequestration at each reservoir is concerned, there are too few wells. Of course including additional wells, at justified and proper depths, will increase construction (and operational) emissions that have not been properly included in the DEIR.

Comment 4 – Mitigation Measures

As an overall comment, none of the mitigation measures for air quality and GHG have verification or monitoring requirements that would provide even reasonable confidence that: (i) the proposed measures are, in fact, being implemented as promised in the DEIR; and (ii) that even if they are being implemented, their effectiveness is similar to that claimed. This includes, for example, monitoring to quantify GHG leakages via the various pathways and sources previously discussed as well as monitoring to address emissions of criteria and air toxic air pollutants from the facilities that are part of the proposed project.

Comment 4.1 – Emission Reduction Agreements and Their Limitations As Proposed Mitigation

The DEIR states repeatedly that, as mitigation, the proposed project will avail itself of a Development Mitigation Contract (DMC) or Voluntary Emission Reduction Agreement (VERA) to address the project's criteria pollutant emissions of NO_x, reactive organic compounds (ROGs) and particulate matter (PM). The goal is to "fully mitigate the project's air quality impacts such that development of the project could be considered to result in no net increase in the designated criteria pollutant emissions over the criteria pollutant emissions that would otherwise exist without the development of the project, all to be verified by the SJVAPCD." In addition, Section 4.10 of Appendix B.1 also makes a similar claim, justifying the lack of any air quality impact (or modeling).

First, this entire construct does not work if the emissions from the project are not properly estimated and/or verifiably and accurately measured. Without such accurate measurements, the amount of mitigation, to achieve "no net increase" using the DMC or similar mechanism is meaningless. Yet, there is nothing in the DEIR that provides any assurance of actual measurements of even these criteria pollutants from each of the project's activities.

Second, as noted in the DEIR, the DMC does not extend to other pollutants, including additional criteria pollutants such as carbon monoxide (CO) or sulfur dioxide (SO_2).

The DMC also does not extend to any of the air toxic compounds that will be emitted as a result of combustion sources and the amine system used for CO_2 concentration. This is true for such air toxics emissions during construction and operations.

Since none of the mitigations identified contain any verifiable measures of their effectiveness and the emissions estimates are simply not verifiable since no monitoring is required, there is a significant uncertainty as to the actual emissions and their impacts (mitigated or otherwise) of air toxic compounds.

Comment 4.2 – Lack of Verification and Effectiveness of PM_{10} Reduction Measures

These are listed in Mitigation Measure 4.3-2. I will not repeat all/both of them for the sake of brevity. But every single item on these lists is simply a promise, with no recordkeeping or

verification. At a minimum, such record-keeping and verification should be included in as part of an enforceable mitigation monitoring plan for PM_{10} (and $PM_{2.5}$) reduction.

Comment 4.3 – The 4,000-foot Setback in MM 4.3-5 Should Be Expanded, as Needed

A reasonable setback distance from any injection well to sensitive receptors is necessary. The DEIR proposes that the setback be 4,000 feet but provides no explanation for this distance.

However, while MM 4.3-5 addresses the setback from injection wells, it is not clear why similar setback distances are not also proposed for other physical infrastructure like pipelines, from which ruptures can cause CO_2 to also escape and could result in adverse impacts to humans and wildlife. For example, if any pipeline passes through a topographically low area, any CO_2 that might escape can accumulate locally and cause adverse impacts. For these reasons, setbacks should be provided from all physical infrastructure associated with the proposed project, based on a site-specific factors such as the locations of such infrastructure and nearby receptors in order to meet CEQA's requirement to provide all feasible mitigation for significant impacts.

Comment 4.4 – MM 4.3-7 and Additional Details of Fence Line Monitoring

While I agree with the goal of MM 4.3-7 that an Air Monitoring program for fence line monitoring of all air constituents generated by the CCS project – including but not limited to criteria pollutants, CO_2, and H_2S – should be developed and implemented, MM 4.3-7 provides no details of how such fence line monitoring will occur. Even basic details of whether this will consist of periodic sampling at specific locations along the fence line (of, say, a well pad; or near the amine units, etc.) or continuous open-path measurements along the entire perimeter of such locations, is not provided in the DEIR. Without this, and additional detail, the efficacy of MM 4.3-7 is not clear. The DEIR should provide additional details, like, for example: (i) specific monitoring parameters (e.g., spacing of monitors, equipment sensitivity, frequency of monitoring) and/or performance standards to be used to select monitoring parameters; (ii) requirements for reporting monitoring results to the County and responsible agencies and for public disclosure of monitoring data and/or performance standards to be used to develop reporting and public disclosure requirements; (iii) any threshold levels (by pollutant) that, if detected at the fence line, will trigger mitigation and/or performance standards to be used to select appropriate thresholds for mitigation; and (iv) mitigation measures to be implemented if monitoring thresholds are exceeded and/or performance standards to be used to select effective mitigation measures.

Attachment A
to Technical Comments of Dr. Ranajit (Ron) Sahu:
Qualifications and Experience

RANAJIT (RON) SAHU, PH.D, CEM (NEVADA)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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EXPERIENCE SUMMARY

Dr. Sahu has over thirty two years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources including stationary and mobile sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over thirty years of project management experience and has successfully managed and executed hundreds of projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past three decades include various trade associations as well as individual companies such as steel mills, petroleum refineries, chemical plants, cement manufacturers, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, land development companies, and various entities in the public sector including EPA, the US Dept. of Justice, several states (including New York, New Jersey, Connecticut, Kansas, Oregon, New Mexico, Pennsylvania, and others), various agencies such as the California DTSC, and various cities and municipalities. Dr. Sahu has executed projects in all 50 US states, numerous local jurisdictions and internationally.

In addition to consulting, for approximately two decades, Dr. Sahu taught numerous courses in several Southern California universities as adjunct faculty, including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management). He also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental and engineering areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.), public sector (such as the US Department of Justice), and public interest group clients with project management, environmental

consulting, project management, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena, CA.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years beginning 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years beginning 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years beginning 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-mid-1990s.

Air and Waste Management Association, West Coast Section, 1989-mid-2000s.

PROFESSIONAL CERTIFICATIONS

EIT, California (#XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, 2000 - 2021.

CEM, State of Nevada (#EM-1699).

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R. Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

“From Purchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada,” with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

“The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants,” with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

A. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

1. In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

B. Matters for which Dr. Sahu has provided affidavits and expert reports include:

2. Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.
3. Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).
4. Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).
5. Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).
6. Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).
7. Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.
8. Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc*., 5:04-cv-00034-KSF (Eastern District of Kentucky).
9. Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.
10. Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.
11. Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.
12. Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.
13. Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

14. Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

15. Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

16. Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

17. Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

18. Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc*., 1:06 CVA 0143 (Southern District of Ohio, Western Division) .

19. Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

20. Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

21. Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

22. Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

23. Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us

24. Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.

25. Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.

26. Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

27. Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).

28. Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

29. Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

30. Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

31. Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

32. Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

33. Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

34. Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.

35. Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).

36. Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

37. Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (District of Colorado).

38. Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

39. Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

40. Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).

41. Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

42. Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

43. Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant*

Generation Company LLC, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).

44. Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

45. Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

46. Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

47. Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority,* Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).

48. Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

49. Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

50. Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.,* Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).

51. Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.,* Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).

52. Declaration (October 2011) on behalf of the Plaintiffs in the matter of *American Nurses Association et. al. (Plaintiffs), v. US EPA (Defendant)*, Case No. 1:08-cv-02198-RMC (US District Court for the District of Columbia).

53. Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (Western District of Washington).

54. Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

55. Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

56. Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).

57. Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

58. Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).

59. Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.

60. Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.

61. Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator, Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.

62. Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.

63. Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

64. Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.

65. Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

66. Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.

67. Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

68. Declaration (April 2013) on behalf of Petitioners in the matter of *Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Resppondents),* Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).

69. Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

70. Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of *A. J. Acosta Company, Inc., v. County of San Bernardino*, Case No. CIVSS803651.

71. Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.

72. Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.

73. Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

74. Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

75. Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).

76. Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).

77. Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of *Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al.,* Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).

78. Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).

79. Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

80. Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).

81. Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).

82. Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

83. Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

84. *Declaration (January 2015) relating to Startup/Shutdown in the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.*

85. Pre-filed Direct Testimony (March 2015), Supplemental Testimony (May 2015), and Surrebuttal Testimony (December 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.

86. Brief of Amici Curiae Experts in Air Pollution Control and Air Quality Regulation in Support of the Respondents, On Writs of Certiorari to the US Court of Appeals for the District of Columbia, No. 14-46, 47, 48. *Michigan et. al., (Petitioners) v. EPA et. al., Utility Air Regulatory Group (Petitioners) v. EPA et. al., National Mining Association et. al., (Petitioner) v. EPA et. al.,* (Supreme Court of the United States).

87. Expert Report (March 2015) and Rebuttal Expert Report (January 2016) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

88. Declaration (April 2015) relating to various Technical Corrections for the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.

89. Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).

90. Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

91. Declaration (August 2015, Docket No. 1570376) in support of "Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation's Emergency Motion;" Declaration (September 2015, Docket No. 1574820) in support of "Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur;" Declaration (October 2015) in support of "Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors to State and Certain Industry Petitioners' Motion to Govern, *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).

92. Declaration (September 2015) in support of the Draft Title V Permit for Dickerson Generating Station (Proposed Permit No 24-031-0019) on behalf of the Environmental Integrity Project.

93. Expert Report (Liability Phase) (December 2015) and Rebuttal Expert Report (February 2016) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., Environmental Law and Policy Center, and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

94. Declaration (December 2015) in support of the Petition to Object to the Title V Permit for Morgantown Generating Station (Proposed Permit No 24-017-0014) on behalf of the Environmental Integrity Project.

95. Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency et al.,* ERAC Case No. 14-256814.

96. Affidavit (January 2016) on behalf of Bridgewatch Detroit in the matter of *Bridgewatch Detroit v. Waterfront Petroleum Terminal Co., and Waterfront Terminal Holdings, LLC.*, in the Circuit Court for the County of Wayne, State of Michigan.

97. Expert Report (February 2016) and Rebuttal Expert Report (July 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.

98. Direct Testimony (May 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.

99. Declaration (June 2016) relating to deficiencies in air quality analysis for the proposed Millenium Bulk Terminal, Port of Longview, Washington.

100. Declaration (December 2016) relating to EPA's refusal to set limits on PM emissions from coal-fired power plants that reflect pollution reductions achievable with fabric filters on behalf of Environmental Integrity Project, Clean Air Council, Chesapeake Climate Action Network, Downwinders at Risk represented by Earthjustice in the matter of *ARIPPA v EPA, Case No. 15-1180.* (D.C. Circuit Court of Appeals).

101. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

102. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Backus Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

103. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Drakulic Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

104. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Deutsch Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

105. Affidavit (February 2017) pertaining to deficiencies water discharge compliance issues at the Wood River Refinery in the matter of *People of the State of Illinois (Plaintiff) v. Phillips 66 Company, ConocoPhillips Company, WRB Refining LP (Defendants)*, Case No. 16-CH-656, (Circuit Court for the Third Judicial Circuit, Madison County, Illinois).

106. Expert Report (March 2017) on behalf of the Plaintiff pertaining to non-degradation analysis for waste water discharges from a power plant in the matter of *Sierra Club (Plaintiff) v. Pennsylvania Department of Environmental Protection (PADEP) and Lackawanna Energy Center*, Docket No. 2016-047-L (consolidated), (Pennsylvania Environmental Hearing Board).

107. Expert Report (March 2017) on behalf of the Plaintiff pertaining to air emissions from the Heritage incinerator in East Liverpool, Ohio in the matter of *Save our County (Plaintiff) v. Heritage Thermal Services, Inc. (Defendant), Case No. 4:16-CV-1544-BYP*, (US District Court for the Northern District of Ohio, Eastern Division).

108. Rebuttal Expert Report (June 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight (Plaintiffs) v Coyote Creek Mining Company LLC (Defendant),* Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).

109. Expert Affidavit (August 2017) and Penalty/Remedy Expert Affidavit (October 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant,)* Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).

110. Expert Report (August 2017) on behalf of Appellant in the matter of *Patricia Ann Troiano (Appellant) v. Upper Burrell Township Zoning Hearing Board (Appellee)*, Court of Common Pleas of Westmoreland County, Pennsylvania, Civil Division.

111. Expert Report (October 2017), Supplemental Expert Report (October 2017), and Rebuttal Expert Report (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

112. Declaration (December 2017) on behalf of the Environmental Integrity Project in the matter of permit issuance for ATI Flat Rolled Products Holdings, Breckenridge, PA to the Allegheny County Health Department.

113. Expert Report (Harm Phase) (January 2018), Rebuttal Expert Report (Harm Phase) (May 2018) and Supplemental Expert Report (Harm Phase) (April 2019) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

114. Declaration (February 2018) on behalf of the Chesapeake Bay Foundation, et. al., in the matter of the Section 126 Petition filed by the state of Maryland in *State of Maryland v. Pruitt (Defendant)*, Civil Action No. JKB-17-2939 (Consolidated with No. JKB-17-2873) (US District Court for the District of Maryland).

115. Direct Pre-filed Testimony (March 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of *NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC*, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington.

116. Expert Affidavit (April 2018) and Second Expert Affidavit (May 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.

117. Direct Pre-filed Testimony and Affidavit (December 2018) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).

118. Expert Report (February 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.

119. Declaration (March 2019) on behalf of Earthjustice in the matter of comments on the renewal of the Title V Federal Operating Permit for Valero Houston refinery.

120. Expert Report (March 2019) on behalf of Plaintiffs for Class Certification in the matter of *Resendez et al v Precision Castparts Corporation* in the Circuit Court for the State of Oregon, County of Multnomah, Case No. 16cv16164.

121. Expert Report (June 2019), Affidavit (July 2019) and Rebuttal Expert Report (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellants) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.

122. Affidavit/Expert Report (August 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.

123. Expert Report (October 2019) relating to the appeal of air permit (Plan Approval) on behalf of Appellants in the matter of *Clean Air Council and Environmental Integrity Project (Appellants) v. Commonwealth of Pennsylvania Department of Environmental Protection and Sunoco Partners Marketing and Terminals L.P.*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-057-L.

124. Expert Report (December 2019), Affidavit (March 2020), Supplemental Expert Report (July 2020), and Declaration (February 2021) on behalf of Earthjustice in the matter of *Objection to the*

Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.

125. Affidavit (December 2019) on behalf of Plaintiff-Intervenor (Surfrider Foundation) in the matter of *United States and the State of Indiana (Plaintiffs), Surfrider Foundation (Plaintiff-Intervenor), and City of Chicago (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant),* Civil Action No. 2:18-cv-00127 (US District Court for the Northern District of Indiana, Hammond Division).

126. Declarations (January 2020, February 2020, May 2020, July 2020, and August 2020) and Pre-filed Testimony (April 2021) in support of Petitioner's Motion for Stay of PSCAA NOC Order of Approval No. 11386 in the matter of the *Puyallup Tribe of Indians v. Puget Sound Clean Air Agency (PSCAA) and Puget Sound Energy (PSE),* before the State of Washington Pollution Control Hearings Board, PCHB No. P19-088.

127. Expert Report (April 2020) on behalf of the plaintiff in the matter of Orion Engineered Carbons, GmbH (Plaintiff) vs. Evonik Operations, GmbH (formerly Evonik Degussa GmbH) (Respondent), before the German Arbitration Institute, Case No. DIS-SV-2019-00216.

128. Expert Independent Evaluation Report (June 2020) for *PacifiCorp's Decommissioning Costs Study Reports dated January 15, 2020 and March 13, 2020 relating to the closures of the Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, Hayden, and Colstrip (Units 3&4) plants*, prepared for the Oregon Public Utility Commission (Oregon PUC).

129. Direct Pre-filed Testimony (July 2020) on behalf of the Sierra Club in the matter of *the Application of the Ohio State University for a certificate of Environmental Compatibility and Public Need to Construct a Combined Heat and Power Facility in Franklin County, Ohio*, before the Ohio Power Siting Board, Case No. 19-1641-EL-BGN.

130. Expert Report (August 2020) and Rebuttal Expert Report (September 2020) on behalf of WildEarth Guardians (petitioners) in the matter of *the Appeals of the Air Quality Permit No. 7482-M1 Issued to 3 Bear Delaware Operating – NM LLC (EIB No. 20-21(A) and Registrations Nos. 8729, 8730, and 8733 under General Construction Permit for Oil and Gas Facilities (EIB No. 20-33 (A)*, before the State of New Mexico, Environmental Improvement Board.

131. Expert Report (July 2020) on the *Initial Economic Impact Analysis (EIA) for A Proposal To* Regulate *NOx Emissions from Natural Gas Fired Rich-Burn Natural Gas Reciprocating Internal Combustion Engines (RICE) Greater Than 100 Horsepower* prepared on behalf of Earthjustice and the National Parks Conservation Association in the matter of Regulation Number 7, Alternate Rules before the Colorado Air Quality Control Commission.

132. Expert Report (August 2020) and Supplemental Expert Report (February 2021) on the Potential Remedies to Avoid Adverse Thermal Impacts from the Merrimack Station on behalf of Plaintiffs in the matter of *Sierra Club Inc. and the* Conservation *Law Foundation (Plaintiffs) v. Granite Shore Power, LLC et. al., (Defendants)*, Civil Action No. 19-cv-216-JL (US District Court for the District of New Hampshire.)

133. Expert Report (August 2020) and Supplemental Expert Report (December 2020) on behalf of Plaintiffs in the matter of *PennEnvironment Inc., and Clean Air Council (Plaintiffs) and Allegheny County Health Department (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant)*, Civil Action No. 2-19-cv-00484-MJH (US District Court for the Western District of Pennsylvania.)

134. Pre-filed Direct Testimony (October 2020) and Sur-rebuttal Testimony (November 2020) on behalf of petitioners (Ten Persons Group, including citizens, the Town of Braintree, the Town of Hingham, and the City of Quincy) in the matter of Algonquin Gas Transmission LLC, Weymouth MA, No. X266786 Air Quality Plan Approval, before the Commonwealth of Massachusetts, Department of Environmental Protection, the Office of Appeals and Dispute Resolution, OADR Docket Nos. 2019-008, 2019-009, 2019010, 2019-011, 2019-012 and 2019-013.

135. Expert Report (November 2020) on behalf of Protect PT in the matter of *Protect PT v. Commonwealth of Pennsylvania Department of Environmental Protection and Apex Energy (PA) LLC*, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2018-080-R (consolidated with 2019-101-R)(the "Drakulic Appeal").

136. Expert Report (December 2020) on behalf of Plaintiffs in the matter of *Sierra Club Inc. (Plaintiff) v. GenOn Power Midwest LP (Defendants)*, Civil Action No. 2-19-cv-01284-WSS (US District Court for the Western District of Pennsylvania.)

137. Pre-filed Testimony (January 2021) on behalf of the Plaintiffs (Shrimpers and Fishermen of the Rio Grande Valley represented by Texas RioGrande Legal Aid, Inc.) in the matter of the Appeal of Texas Commission on Environmental Quality (TCEQ) Permit Nos. 147681, PSDTX1522, GHGPSDTX172 for the Jupiter Brownsville Heavy Condensate Upgrader Facility, Cameron County, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-21-0111, TCEQ Docket No. 2020-1080-AIR.

138. Expert Reports (March 2021 and May 2021) regarding the Aries Newark LLC Sludge Processing Facility, Application No. CPB 20-74, Central Planning Board, City of Newark, New Jersey.

139. Expert Report (April 2021) for *Charles Johnson Jr. (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant),* Civil Action No. 2:20-CV-01329 (Related to 12-968 BELO in MDL No. 2179). (US District Court for the Eastern District of Louisiana, New Orleans Division).

140. Affidavit (April 2021) for *Clayton Faerber et.al., (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 20-CV-00328 01329 (Related to 12-968 BELO in MDL No. 2179). (US District Court for the Southern District of Mississippi).

141. Expert Report (April 2021, June 2023) for *Floyd Ruffin (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 2:20-cv-00334-CJB-JCW (US District Court for the Eastern District of Louisiana, New Orleans Division).

142. Expert Report (April 2021) and Sur-Rebuttal Report (June 2021) on behalf of the Plaintiffs in the matter of *Modern Holdings, LLC, et al. (Plaintiffs) v. Corning Inc., et al. (Defendants)*, Civil Action No. 5:13-cv-00405-GFVT, (US District Court for the Eastern District of Kentucky, Central Division at Lexington).

143. Expert Report (May 2021) for *Clifford Osmer (Plaintiff) v. BP Exploration and Production Inc., et. al., (Defendants)* related to No. 18-CV-12557 (US District Court for the Eastern District of Louisiana).

144. Expert Report (May 2021) and Rebuttal Expert Report (January 2022) for *James Noel (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant),* Civil Action No. 1:19-CV-00694-JB-MU-C (US District Court for the Southern District of Alabama, Southern Division).

145. Expert Report (June 2021) and Declarations (May 2021 and June 2021) on behalf of Plaintiffs in the matter of *Sierra Club (Plaintiff) v. Woodville Pellets, LLC (Defendant)*, Civil Action No. 9:20-cv-00178-MJT (US District Court for the Eastern District of Texas, Lufkin Division.)

146. Expert Witness Disclosure (June 2021) on behalf of the Plaintiffs in the matter of *Jay Burdick, et. al., (Plaintiffs) v. Tanoga Inc. (d/b/a Taconic) (Defendant)*, Index No. 253835, (State of New York Supreme Court, County of Rensselaer).

147. Expert Report (June 2021) on behalf of Appellants in the matter of *PennEnvironment and Earthworks (Appellants) v. Commonwealth of Pennsylvania Department of Environmental Protection (Appellee) and MarkWest Liberty Midstream and resource, LLC (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2020-002-R.

148. Expert Report (June 2021) for *Antonia Saavedra-Vargas (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 2:18-CV-11461 (US District Court for the Eastern District of Louisiana, New Orleans Division).

149. Affidavit (June 2021) for Lourdes Rubi in the matter of *Lourdes Rubi (Plaintiff) v. BP Exploration and Production Inc., et. al., (Defendants)*, related to 12-968 BELO in MDL No. 2179 (US District Court for the Eastern District of Louisiana, New Orleans Division).

150. Expert Report (June 2021) for *Wallace Smith (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 2:19-CV-12880 (US District Court for the Eastern District of Louisiana, New Orleans Division).

151. Declaration (July 2021) on behalf of Plaintiffs in the matter of *Stephanie Mackey and Nick Migliore, on behalf* of *themselves and all others similarly situated (Plaintiffs) v. Chemtool Inc. and Lubrizol Corporation (Defendants)*, Case No. 2021-L-0000165, State of Illinois, Circuit Court of the 17th Judicial Circuit, Winnebago County.

152. Declaration (July 2021, August 2021) on behalf of Petitioners in the matter of the Petition for a Hearing on the Merits Regarding Air Quality Permit No. 3340-RMD issued to New Mexico Terminal Services, LLC by *Mountain View Neighborhood Association et. al., (Petitioners) v. City of Albuquerque Environmental Health Department*, AQCB Petition No. 2020-1 before the Albuquerque-Bernalillo County Air Quality Control Board.

153. Expert Disclosure (September 2021) and Affidavit (May 2023) on behalf of the Plaintiffs in the matter of *State of New York, Town of Hempstead, Town of Brookhaven, Incorporated Village of Garden City and Long Island Power Authority et. al., (Plaintiffs) v. Covanta Hempstead Company et. al., (Defendants)*, Index No. 7549/2013 before the Supreme Court of the State of New York, County of Nassau.

154. Expert Report (October 2021) for *John A. Battiste (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant),* Civil Action No. 1:21-CV-00118 (US District Court for the Southern District of Alabama, Mobile Division)

155. Declaration/Expert Report (October 2021) for *Charles K. Grasley et. al., (Plaintiffs) v. Chemtool Incorporated (Defendant)*, Case No. 2021-L-0000162 (State of Illinois, In the Circuit Court of the 17th Judicial Circuit, Winnebago County).

156. Declaration (October 2021) and Expert Report (November 2021) on behalf of the Plaintiffs in the matter of Toll Brothers, Inc., and Porter Ranch Development Company (Plaintiffs) v. Sempra Energy, Southern California Gas Company et. al., (Defendants), Southern California [Aliso Canyon] Gas Leak Cases, JCCP No.: 4861, Lead Case No.: BC674622, Superior Court of the State of California for the County of Los Angeles.

157. Expert Report (November 2021) and Declaration (September 2022) on behalf of Plaintiffs in Re: Deepwater Horizon BELO Cases, Case No. 3:19cv963-MCR-GRJ (US District Court for the Northern District of Florida, Pensacola Division).

158. Declaration (November 2021) for the *United States of America and the State of Kansas, Department of Health and Environment (Plaintiffs) v. Coffeyville Resources Refining & Marketing, LLC (Defendant)*, Civ. No. 6:04-cv-01064-JAR-KGG (US District Court for the District of Kansas).

159. Expert Report/Affidavit (December 2021) on behalf of the City of Detroit in the matter of Marathon Petroleum Company (Claimant) v. City of Detroit Building Safety Engineering and Environmental Department, BSEED Case No. MCR 2018-2525, DAH Appeal No. 21-SWA-01, before the State of Michigan, City of Detroit Department of Appeals and Hearings.

160. Expert Report (December 2021) for *John Pabst (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 21-CV-00290 (US District Court for the Eastern District of Louisiana).

161. Expert Report (December 2021) for *Audrey Annette Tillery-Perdue individually and as person representative of the estate of Eddie Lewis Perdue (Plaintiff) v. BP Exploration and Production Inc., et. al., (Defendant)*, Civil Action No. 5:19-cv-00052-MCR-GRJ (US District Court for the Northern District of Florida, Pensacola Division).

162. Expert Report (February 2022) for *Richard Dufour (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 19-cv-00591 (US District Court for the Southern District of Mississippi).

163. Expert Report (February 2022) and Rebuttal Expert Report (June 2022, in preparation) for *Kamuda (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010475 (Circuit Court of Cook County, Illinois).

164. Expert Report (February 2022) in the matter of the *Appeal Petition for Hearing on Air Quality Permit No. 8585 on behalf of Earth Care New Mexico et. al., (Petitioners) v. New Mexico Environment Department and Associated Asphalt and Materials, LLC (Applicant),* No. EIB 21-48 before the State of New Mexico Environmental Improvement Board.

165. Expert Report (March 2022), Affidavit (June 2022), Supplemental Expert Report (April 2023) in the matter of *Clean Air Council et. al., (Appellants) v. Commonwealth of Pennsylvania, Department of Environmental Protection (Appellee) and Renovo Energy Center (Permittee)* EHB Docket No. 2021-055-R before the Commonwealth of Pennsylvania Environmental Hearing Board.

166. Declaration (March 2022) in the matter of Max Midstream Texas LLC Air Quality Permit No. 162941 for the Seahawk Crude Condensate Terminal in Calhoun County Texas, TCEQ Docket No. 2022-0157-AIR, before the Texas Commission on Environmental Quality.

167. Expert Pre-filed Testimony (April 2022) in the matter of Application of TPC Group LLC for New State and PSD Air Quality Permits (various), TCEQ Docket No. 2021-1422-AIR, SOAH Docket No. 582-22-0799, Before the Texas State Office of Administrative Hearings.

168. Expert Report (April 2022) and Rebuttal Report (August 2022) for *Teresa Fornek (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010744 (Circuit Court of Cook County, Illinois.)

169. Rule 26 Disclosure (May 2022) in the matter of the *Water Works and Sewer Board of the City of Gadsden (*Plaintiff*) v. 3M Company, et. al., (Defendants)*, Civil Action No.: 31 CV-2016-900676.00 (Circuit County of Etowah County, Alabama)

170. Expert Report (June 2022) for *Heather Schumacher (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-011939 (Circuit Court of Cook County, Illinois.)

171. Expert Report (June 2022), Rebuttal Reports (August 2022, September 2022) for Plaintiffs in *Phylliss Grayson et. al. (Plaintiffs), v Lockheed Martin Corporation (Defendant),* Case No. 6:20-cv-01770. (US District Court for the Middle District of Florida – Orlando Division.)

172. Expert Affidavit (July 2022) for Center for Environmental Rights in connection with the 2019 South Africa Integrated Resource Plan in *African Climate Alliance et. al. v. The Minister of Mineral Resources and Energy et. al.*, in the High Court of South Africa, Gauteng Division, Pretoria.

173. Expert Affidavit (July 2022) for Center for Environmental Rights in connection with the Limpopo Mine (Lephalale Coal Mines Ltd.) in *Earthlife Africa v. The Minister of Forestry, Fisheries and Environment et. al.*, in the High Court of South Africa, Gauteng Division, Pretoria, Case No. 9149/2022.

174. Pre-filed Testimony (July 2022) and Rebuttal Testimony (September 2020) on behalf of the Puyallup Tribe of Indians in the matter of *Washington Utilities and Transportation Commission (Complainant) v. Puget Sound Energy (Respondent)* before the Washington Utilities and Transportation Commission, Docket UE-220066 and UG-220067 (Consolidated).

175. Expert Report (September 2022) *Clean Air Council, Citizens for Pennsylvania's Future, Mountain Watershed Association (Appellants) v. Allegheny County Health Department (Appellee) and Allegheny Energy Center (*Intervenor*, Permittee),* Case No. 21-043 before the Hearing Officer of the Allegheny County Health Department.

176. Expert Affidavit (October 2022) for *Concerned Citizens of Cook County GA (Petitioner) v. Georgia Department of Natural Resources (Respondent) and Spectrum Energy Georgia, LLC (Respondent Intervenor)* before the Office of State Administrative Hearings, State of Georgia, Docket No: 2303405-OSAH-BNR-AQ-37-Barnes.

177. Expert Rebuttal Report (January 2023), Supplemental Rebuttal Expert Report (March 2023, May 2023, November 2023) for *Ann Jordan et. al., and Blake Darnell (Plaintiffs) v. Terumo BCT et. al., (Defendants)* before District Court, Jefferson County, Colorado Case Numbers: 2020CV031457, 2021CV030474 (consolidated with 2020CV031457) and 2020CV03148.

178. Expert Report (January 2023) and Rebuttal Expert Report (April 2023) for *Potomac Riverkeeper and Sierra Club (Plaintiffs) v. Virginia Electric and Power Company (Defendant)*, Civil Action No. 2:21-CV-23 (Kleeh) (US District Court for the Northern District of West Virginia, Elkins Division).

179. Affidavit (January 2023) for *Richard Dufour (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 1:19-cv-00591-HSO-BWR (Related to 12-968 BELO in MDL No. 2179). (US District Court for the Southern District of Mississippi).

180. Expert Report (January 2023) and Supplemental Expert Report (July 2023) on behalf of Plaintiffs in the matter of *Stephanie* Mackey *et. al., (Plaintiffs) v. Chemtool Inc. et. al., (Defendants) and Holian Insulation Company Inc. (Third-party Defendant)*, Case No.: 3:21-cv-50283, U.S. District Court, Northern District of Ilinois, Western Division.

181. Expert Report (February 2023) for *Vervicia Henderson, et al. (Plaintiff) v. Lockheed Martin Corporation (Defendant)*, Case No. 6:21-cv-01363, U.S. District Court, Middle District of Florida, Orlando Division.

182. Expert Report (February 2023) for *Carol Davis (Plaintiff) v. Lockheed Martin Corporation (*Defendant*)*, Case No. 6:22-cv-81-RBD-EJK, U.S. District Court, Middle District of Florida, Orlando Division.

183. Expert Report (February 2023) for Mark Letart (Plaintiff), et al. v. Union Carbide Corporation, et al. (Defendants), Case No. 2:19-cv-877, U.S. District Court, Southern District of West Virginia, Charleston Division.

184. Affidavit (March 2023) on behalf of plaintiffs in the matter of the *State of New Mexico, ex rel. Raul Torrez, Attorney General (Plaintiffs) v. Sterigenics US LLC, Sotera Health Holdings, LLC, Sotera Health LLC and Sotera Health Company (Defendants)*, Case No.: D-307-CV-2020-02629, State of New Mexico, Third Judicial District Court, County of Dona Ana

185. Pre-filed Direct Testimony (March 2023) in the matter of *Algonquin Gas Transmission LLC., on behalf of Community Residents (*Petitioners*)*, Commonwealth of Massachusetts Department of Environmental Protection, Office of Appeals and Dispute Resolution, OADR Docket Nos. 2017-011 and 012, Waterways Application License No. W16-4600, Weymouth Mass.

186. Declaration (April 2023) in the matter of Sierra Club (Plaintiff) v. Tennessee Valley Authority in the matter of the Johnsonville Aeroderivative Combustion Turbines Project, Case No.: 3:22-cv-1054, U.S>, District Court, Middle District of Tennessee, Nashville Division.

187. Expert Report (May 2023/June 2023), Affidavit (April 2023) and Declaration (July 2023) for *Ezequiel Caraballo-Pache (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 8:20-cv-00263-SCB-JSS (US District Court for the Middle District of Florida, Tampa Division).

188. Affidavit (May 2023) for *Lawrence Tucei (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 1:22-cv-00078-HSO-BWR (US District Court for the Southern District of Mississippi).

189. Expert Report (May 2023/June 2023) for *Vincent Culliver (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 3:21-cv-4942-MCR/HTC (US District Court for the Northern District of Florida).

190. Expert Report (June 2023) for *Matthew Williams (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 1:22-cv-00278-LG-BWR (US District Court for the Southern District of Mississippi).

191. Declaration (June 2023) in support of public commenters relating to the Michigan Department of Environment Great Lakes and Energy (EGLE)'s Annual Network Monitoring Plan 2024.

192. Expert Report (July 2023) and Rebuttal Expert Report (September 2023) relating to Greenhouse Gas and Energy Management (GEMM2) for Manufacturing in Colorado (September 2023) on behalf of Environmental Defense Fund.

193. Pre-filed Direct Testimony (July 2023) on behalf of Citizens for Environmental Justice in the matter of the permit Application of Valero Refining-Texas, LP for Modification to State and Prevention of Significant Deterioration Air Quality Permits No. 38754 and PSDTX324M15 before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-23-14975, TCEQ Docket No. 2023-0203-AIR.

194. Declaration (August 2023) in support of comments by Environmental Defense Fund in connection with the "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, published at 88 Fed. Reg. 36,654 (June 5, 2023) ("Final Rule"), Docket ID No. EPA-HQ-OAR-2021-0668.

195. Expert Report (August 2023) on behalf of Appellants in the matter of *PennEnvironment and Sierra Club (Appellants) v. Commonwealth of Pennsylvania, Department of Environmental Protection, (Appellee), and PPG Industries, Inc. (Permittee)*, EHB Docket No. 2022-032-B. Environmental Hearing Board, Department of Environmental Protection, State of Pennsylvania.

196. Pre-filed Testimony (September 2023) and Cross Answering Testimony (October 2023) on behalf of the Puyallup Tribe of Indians in the matter of *Washington Utilities and Transportation Commission (Complainant) v. Puget Sound Energy (Respondent)*, Docket: UG-230393. Before the Washington Utilities and Transportation Commission.

197. Expert Report (December 2023) on behalf of plaintiffs in the matter of *PennEnvironment and Sierra Club (Plaintiffs) v. PPG Industries, Inc. (Defendant).* Case No.: Civil Action Nos. 2:12-cv-00342, 2:12-cv-00527, 2:13-cv-01395, 1:13-cv-01396, 2:14cv-00229 (consolidated). U.S. District Court Western District of Pennsylvania.

C. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in similar proceedings</u> include the following:

198. Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.

199. Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

200. Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

201. Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

202. Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).

203. Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.

204. Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.

205. Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.

206. Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.

207. Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.

208. Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

209. Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al*.

210. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

211. Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

212. Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

213. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

214. Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

215. Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

216. Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

217. Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

218. Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

219. Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

220. Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

221. Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

222. Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

223. Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

224. Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

225. Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

226. Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

227. Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

228. Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

229. Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

230. Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

231. Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

232. Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

233. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

234. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation*

Company LLC, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

235. Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

236. Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

237. Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

238. Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the *US Federal Trade Commission (FTC) v. ECM Biofilms* (FTC Docket #9358).

239. Deposition (February 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

240. Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

241. Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

242. Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.

243. Deposition (May 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

244. Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

245. Deposition (April 2016) on behalf of the Plaintiffs in *UNatural Resources Defense Council, Respiratory Health Association, and Sierra Club (Plaintiffs) v. Illinois Power Resources LLC and Illinois Power Resources Generation LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (Central District of Illinois, Peoria Division).

246. Trial Testimony at Hearing (July 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.

247. Trial Testimony (December 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.

248. Trial Testimony (July-August 2016) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

249. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

250. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Backus Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

251. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Drakulic Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

252. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Deutsch Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

253. Deposition Testimony (July 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight v Coyote Creek Mining Company LLC (Defendant)* Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).

254. Deposition Testimony (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

255. Deposition Testimony (December 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant)* Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).

256. Deposition Testimony (January 2018) in the matter of National Parks Conservation Association (NPCA) v. State of Washington Department of Ecology and British Petroleum (BP) before the Washington Pollution Control Hearing Board, Case No. 17-055.

257. Trial Testimony (January 2018) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).

258. Trial Testimony (April 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington.

259. Deposition (June 2018) (harm Phase) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).

260. Trial Testimony (July 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.

261. Deposition (January 2019) and Trial Testimony (January 2019) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).

262. Deposition (February 2019) and Trial Testimony (March 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric

Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.

263. Deposition (June 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.

264. Deposition (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellants) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.

265. Deposition (December 2019) on behalf of the Plaintiffs in the matter of David Kovac, individually and on behalf of wrongful death class of Irene Kovac v. BP Corporation North America Inc., Circuit Court of Jackson County, Missouri (Independence), Case No. 1816-CV12417.

266. Deposition (February 2020, virtual) and testimony at Hearing (August 2020, virtual) on behalf of Earthjustice in the matter of *Objection to the Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation*, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.

267. Hearing (July 14-15, 2020, virtual) on behalf of the Sierra Club in the matter of *the Application of the Ohio State University for a certificate of Environmental Compatibility and Public Need to Construct a Combined Heat and Power Facility in Franklin County, Ohio*, before the Ohio Power Siting Board, Case No. 19-1641-EL-BGN.

268. Hearing (September 2020, virtual) on behalf of WildEarth Guardians (petitioners) in the matter of *the Appeals of the Air Quality Permit No. 7482-M1 Issued to 3 Bear Delaware* Operating – *NM LLC (EIB No. 20-21(A) and Registrations Nos. 8729, 8730, and 8733 under General Construction Permit for Oil and Gas Facilities (EIB No. 20-33 (A)*, before the State of New Mexico, Environmental Improvement Board.

269. Deposition (December 2020, March 4-5, 2021, all virtual) and Hearing (April 2021, virtual) in support of Petitioner's Motion for Stay of PSCAA NOC Order of Approval No. 11386 in the matter of the *Puyallup Tribe of Indians v. Puget Sound Clean Air Agency (PSCAA) and Puget Sound Energy (PSE),* before the State of Washington Pollution Control Hearings Board, PCHB No. P19-088.

270. Hearing (September 2020, virtual) on the *Initial Economic Impact Analysis (EIA) for A Proposal To* Regulate *NOx Emissions from Natural Gas Fired Rich-Burn Natural Gas Reciprocating Internal Combustion Engines (RICE) Greater Than 100 Horsepower* prepared on behalf of Earthjustice and the National Parks Conservation Association in the matter of Regulation Number 7, Alternate Rules before the Colorado Air Quality Control Commission.

271. Deposition (December 2020, virtual and Hearing February 2021, virtual) on behalf of the Plaintiffs (Shrimpers and Fishermen of the Rio Grande Valley represented by Texas RioGrande Legal Aid, Inc.) in the matter of the Appeal of Texas Commission on Environmental Quality (TCEQ) Permit Nos. 147681, PSDTX1522, GHGPSDTX172 for the Jupiter Brownsville Heavy Condensate Upgrader Facility, Cameron County, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-21-0111, TCEQ Docket No. 2020-1080-AIR.

272. Deposition (January 2021, virtual) on behalf of Plaintiffs in the matter of *PennEnvironment Inc., and Clean Air Council (Plaintiffs) and Allegheny County Health Department (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant)*, Civil Action No. 2-19-cv-00484-MJH (US District Court for the Western District of Pennsylvania.)

273. Deposition (February 2021, virtual) on behalf of Plaintiffs in the matter of *Sierra Club Inc. (Plaintiff) v. GenOn Power Midwest LP (*Defendants*)*, Civil Action No. 2-19-cv-01284-WSS (US District Court for the Western District of Pennsylvania.)

274. Deposition (April 2021, virtual) on the Potential Remedies to Avoid Adverse Thermal Impacts from the Merrimack Station on behalf of Plaintiffs in the matter of *Sierra Club Inc. and the* Conservation *Law Foundation (Plaintiffs) v. Granite Shore Power, LLC et. al., (Defendants)*, Civil Action No. 19-cv-216-JL (US District Court for the District of New Hampshire.)

275. Deposition (June 2021, virtual) on behalf of Plaintiffs in the matter of *Sierra Club (Plaintiff) v. Woodville Pellets, LLC (Defendant)*, Civil Action No. 9:20-cv-00178-MJT (US District Court for the Eastern District of Texas, Lufkin Division).

276. Deposition (June 2021, virtual) on behalf of the Plaintiffs in the matter of *Modern Holdings, LLC, et al. (Plaintiffs) v. Corning Inc., et al. (Defendants)*, Civil Action No. 5:13-cv-00405-GFVT, (US District Court for the Eastern District of Kentucky, Central Division at Lexington).

277. Testimony (June 2021, virtual) regarding the Aries Newark LLC Sludge Processing Facility, Application No. CPB 20-74, (Central Planning Board, City of Newark, New Jersey).

278. Testimony at Hearing (October 2021) on behalf of Evraz Rocky Mountain Steel in the matter of Colorado's Proposed Revisions to Regulation 22, the Greenhouse Gas Emissions and Energy Management for the Manufacturing Sector in Colorado (GEMM Rule), before the Colorado Air Quality Control Commission.

279. Deposition (November 2021) for *Charles Johnson Jr. (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant),* Civil Action No. 2:20-CV-01329 (Related to 12-968 BELO in MDL No. 2179). (US District Court for the Eastern District of Louisiana).

280. Testimony at Hearing (November 2021) on behalf of *National Parks Conservation Association, et. al*., in the matter of the Proposed Revisions to Colorado's Regional Haze State Implementation Plan (SIP) and Colorado Regulation 23, before the Colorado Air Quality Control Commission.

281. Deposition (December 2021) on behalf of Plaintiffs in Re: Deepwater Horizon BELO Cases, Case No. 3:19cv963-MCR-GRJ (US District Court for the Northern District of Florida, Pensacola Division).

282. Deposition (December 2021) for *James Noel (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant),* Civil Action No. 1:19-CV-00694-JB-MU-C (US District Court for the Southern District of Alabama, Southern Division).

283. Testimony at Hearing (February 2022, virtual) in the matter of the *Appeal Petition for Hearing on Air Quality Permit No. 8585 on behalf of Earth Care New Mexico et. al., (Petitioners) v. New Mexico Environment Department and Associated Asphalt and Materials, LLC (Applicant),* No. EIB 21-48 before the State of New Mexico Environmental Improvement Board.

284. Deposition (March 2022) and Rebuttal Deposition (July 2022) for *Kamuda (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010475 (Circuit Court of Cook County, Illinois.)

285. Deposition (April 2022, virtual) in the matter of Application of TPC Group LLC for New State and PSD Air Quality Permits (various), TCEQ Docket No. 2021-1422-AIR, SOAH Docket No. 582-22-0799, Before the Texas State Office of Administrative Hearings.

286. Deposition (May 2022, virtual) in the matter of the *Water Works and Sewer Board of the City of Gadsden (Plaintiff) v. 3M Company, et. al., (*Defendants*)*, Civil Action No.: 31 CV-2016-900676.00 (Circuit County of Etowah County, Alabama)

287. Deposition (June 2022 and September 2022, both virtual) for *Teresa* Fornek *(Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010744 (Circuit Court of Cook County, Illinois.)

288. Deposition (June 2022, virtual) on behalf of the Plaintiffs in the matter of Toll Brothers, Inc., and Porter Ranch Development Company (Plaintiffs) v. Sempra Energy, Southern California Gas Company et. al., (Defendants), Southern California [Aliso Canyon] Gas Leak Cases, JCCP No.: 4861, Lead Case No.: BC674622, Superior Court of the State of California for the County of Los Angeles.

289. Deposition (July 2022) for *Richard Dufour (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 19-cv-00591 (US District Court for the Southern District of Mississippi).

290. Trial (August 2022) on behalf of the Plaintiffs in the matter of Modern *Holdings, LLC, et al. (Plaintiffs) v. Phillips (Defendants)*, Civil Action No. 5:13-cv-00405-GFVT, (US District Court for the Eastern District of Kentucky, Central Division at Lexington).

291. Trial (August 2022, in person) for *Susan Kamuda (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010475 (Circuit Court of Cook County, Illinois).

292. Deposition (September 2022, virtual) for *Heather Schumacher (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010744 (Circuit Court of Cook County, Illinois.)

293. Deposition (September 2022) on behalf of Plaintiffs in *Phylliss Grayson et. al. (Plaintiffs), v Lockheed Martin Corporation (Defendant),* Case No. 6:20-cv-01770. (US District Court for the Middle District of Florida – Orlando Division.)

294. Deposition (September 2022) for *Teresa Fornek (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010475 (Circuit Court of Cook County, Illinois).

295. Hearing (October 2022) on behalf of the Puyallup Tribe of Indians in the matter of *Washington Utilities and Transportation Commission (Complainant) v. Puget Sound Energy (Respondent)* before the Washington Utilities and Transportation Commission, Docket UE-220066 and UG-220067 (Consolidated).

296. Trial (October 2022, in person) for *Teresa Fornek (Plaintiff) v. Sterigenics U.S., LLC, et. al., (Defendant)*, Case No. 2018-L-010475 (Circuit Court of Cook County, Illinois).

297. Depositions (March 2023, June 2023) for *Ann Jordan et. al., and Blake Darnell (Plaintiffs) v. Terumo BCT et. al., (Defendants)* before District Court, Jefferson County, Colorado Case Numbers: 2020CV031457, 2021CV030474 (consolidated with 2020CV031457) and 2020CV03148.

298. Depositions (March 2023, April 2023, May 2023) for Quinn Buczek (Plaintiff) v. Sterigenics US, LLC, Sotera Health, LLC, Prologis First US Properties, LP, et. al., (Defendants) before State Court of Gwinnett County, State of Georgia, Case No. Civil Action File No. 20-C-05918-S1.

299. Deposition (May 2023) for *Potomac Riverkeeper and Sierra Club (Plaintiffs) v. Virginia Electric and Power Company (Defendant)*, Civil Action No. 2:21-CV-23 (Kleeh) (US District Court for the Northern District of West Virginia, Elkins Division).

300. Deposition (May 2023) for Mark Letart (Plaintiff), et al. v. Union Carbide Corporation, et al. (Defendants), Case No. 2:19-cv-877, U.S. District Court, Southern District of West Virginia, Charleston Division.

301. Testimony at Hearing on behalf of Evraz North America In the Matter of Colorado Air Quality Regulation Proposed Revisions to Regulation Number 3 to establish enhanced Modeling, monitoring and permitting requirements for Stationary sources in disproportionately impacted communities 5 CCR 1001-5, before the Air Quality Control Commission, State of Colorado.

302. Deposition (2023) for *Vervicia Henderson, et al. (Plaintiff) v. Lockheed Martin Corporation (Defendant)*, Case No. 6:21-cv-01363, U.S. District Court, Middle District of Florida, Orlando Division.

303. Testimony at Hearing (July 2023) *Clean Air Council, Citizens for Pennsylvania's Future, Mountain* Watershed *Association (Appellants) v. Allegheny County Health Department (Appellee) and Allegheny Energy Center (*Intervenor*, Permittee),* Case No. 21-043 before the Hearing Officer of the Allegheny County Health Department.

304. Deposition (July 2023) for *Ezequiel Caraballo-Pache (Plaintiff) v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 8:20-cv-00263-SCB-JSS (US District Court for the Middle District of Florida, Tampa Division).

305. Deposition (August 2023) for *Floyd Ruffin (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 2:20-cv-00334-CJB-JCW (US District Court for the Eastern District of Louisiana, New Orleans Division).

306. Deposition (August 2023) on behalf of petitioners in *Doreen Carey et; al., (Petitioners) v. Fulcrum Centerpoint LLC. (Permittee/Respondent) and Indiana Department of Environmental Management (Respondent)*, Permit Number 089-44042-00660, before the Indiana Office of Environmental Adjudication.

307. Deposition (August 2023) on behalf of the Plaintiff in the *Water Works and Sewer Board of the Town of Centre, Alabama v. 3M Company, et. al.*, Civil Action No.: CV-2017-900049. Circuit Court of Cherokee County, State of Georgia.

308. Deposition (August 2023) for *Matthew Williams (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 1:22-cv-00278-LG-BWR (US District Court for the Southern District of Mississippi).

309. Deposition (September 2023) for *Vincent Culliver (Plaintiff), v. BP Exploration and Production Inc., et. al. (Defendant)*, Civil Action No. 3:21-cv-4942-MCR/HTC (US District Court for the Northern District of Florida).

310. Testimony at Hearing for Greenhouse Gas and Energy Management (GEMM2) for Manufacturing in Colorado (September 2023) on behalf of Environmental Defense Fund.

311. Testimony at Hearing (October 2023) in the matter of *Algonquin Gas Transmission LLC., on behalf of Community Residents (*Petitioners*)*, Commonwealth of Massachusetts Department of Environmental Protection, Office of Appeals and Dispute Resolution, OADR Docket Nos. 2017-011 and 012, Waterways Application License No. W16-4600, Weymouth Mass.

312. Testimony at Hearing (August 2023) on behalf of Citizens for Environmental Justice in the matter of the permit Application of Valero Refining-Texas, LP for Modification to State and Prevention of Significant Deterioration Air Quality Permits No. 38754 and PSDTX324M15 before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-23-14975, TCEQ Docket No. 2023-0203-AIR.

313. Testimony at Hearing (September 2023) on behalf of Appellants in the matter of *PennEnvironment and Sierra Club (Appellants) v. Commonwealth of Pennsylvania, Department of Environmental Protection, (Appellee), and PPG Industries, Inc. (Permittee)*, EHB Docket No. 2022-032-B. Environmental Hearing Board, Department of Environmental Protection, State of Pennsylvania.

314. Testimony at Hearing (November 2023) on behalf of the Puyallup Tribe of Indians in the matter of *Washington Utilities and Transportation Commission (Complainant) v. Puget Sound Energy (Respondent)*, Docket: UG-230393. Before the Washington Utilities and Transportation Commission.

ATTACHMENT B

Evaluation of Recirculated Draft Environmental Impact Report on Geological Storage of Carbon Dioxide at the Carbon TerraVault I Facility in Kern County, California

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Center for Applied Environmental Science

July 16, 2024

About the Author: Dr. DiGiulio is a retired geoscientist from the U.S. Environmental Protection Agency's Office of Research and Development. He has conducted research on: emissions of volatile organic compounds from abandoned wells, leakage of produced water, condensate, and drilling fluids from impoundments to groundwater, contamination of groundwater from hydraulic fracturing, subsurface methane and carbon dioxide migration (stray gas), intrusion of subsurface vapors into indoor air (vapor intrusion), gas flow-based subsurface remediation (soil vacuum extraction, bioventing), groundwater sampling methodology, soil-gas sampling methodology, gas permeability testing, and solute transport of contaminants in soil. He assisted in the development of EPA's original guidance on vapor intrusion and the EPA's Class VI Rule on geologic sequestration of carbon dioxide (Tier II Committee). He has served as an expert witness in litigation relevant to oil and gas development, testified before State oil and gas commissions on proposed regulation, and testified before Congress on the impact of oil and gas development on water resources. His consulting services to non-government organizations have included reports on: stray methane gas migration, geological carbon storage in Louisiana, storage of natural gas liquids in solution mined caverns, proposed oil and gas regulations in Colorado, impact to groundwater resources from Class II disposal wells in Ohio, Idaho, and Florida, produced water transport in barges along the Ohio River, proposed EPA regulation on discharge of produced water to surface water, and Bureau of Land Management leases in Wyoming, Montana, and Colorado.

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Background

In December 2023, Volume I and Volume II of a Draft Environmental Impact Report (DEIR, 2023a, 2023b) was prepared by Kern County as the Lead Agency under the California Environmental Quality Act (CEQA). County staff has determined, following a review of the written comments and release of the EPA Class VI Permit for Reservoir 26R, that changes should be made in the previously circulated DEIR (DEIR, 2023a). In June 2024, Volume I and Volume II of a Draft Environmental Impact Report (RDEIR, 2024a, 2024b) was recirculated for comment.

This evaluation incorporates by reference and builds on the report I prepared on the December 2023 DEIR. The DEIR report is included as an attachment to comments submitted by Earthjustice on behalf of the Center for Biological Diversity et al. on March 1, 2024.

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of the California Resources Corporation, proposes to inject supercritical carbon dioxide (CO_2) at two locations (26R and A1-A2 reservoirs) in the Monterey Formation at the Elk Hills Oil Field in Kern County, California (RDEIR, 2024a). The source of CO_2 for injection is pre-combustion Elk Hills Oil Field gas, from which CO_2 is captured and processed at the existing cryogenic and fractionation natural gas plant facility and the Elk Hills Power Plant within the Elk Hills Oil Field (RDEIR, 2024a). Currently, the Elk Hills Power Plant provides electricity for both oilfield operations and the California wide power system (RDEIR, 2024a). The project would consist of six injection wells - four (one converted Class II well, three new) within the 26R reservoir and two converted Class II wells within the A1 - A2 reservoir.

At the 26R reservoir, the Monterey Formation is approximately 6,000 feet deep with oil and gas production from turbidite sands (RDEIR, 2024a). Turbidite deposited sands are interbedded with siliceous shale. Sand porosity and permeability averages 25% and 45 millidarcy (mD), respectively (RDEIR, 2024b). At the A1 - A2 reservoir, the Monterey Formation is approximately 8,500 feet deep with oil and gas production also from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 16% and 60 mD, respectively (RDEIR, 2024b).

The 26R reservoir was discovered in the 1940s while the A1 - A2 reservoir was discovered in the 1970s (RDEIR, 2024b). In addition to primary extraction, oil and gas wells have been used for enhanced recovery using water and gas injection over the past 40 years (RDEIR, 2024b).

The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for both the 26R and A1 - A2 reservoirs (RDEIR, 2024a). The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and clay beds. The Reef Ridge Shale is continuous and ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity (RDEIR, 2024b).

At full operation, the project is designed to inject up to 1.46 million tons of CO_2 per year into the 26R reservoir (up to 26 years) and up to 0.75 million tons per year in the A1-A2 reservoir, for a total capacity of 2.21 million tons per year (RDEIR, 2024a). Additionally, 10 existing wells will be converted to monitoring wells, and six existing wells would be converted into seismic monitoring wells (RDEIR, 2024a).

Setbacks and Encroachment

Leakage of CO_2 from wellbores is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2 (Jordan and Benson, 2009, Zhang and Bachu, 2011). There is interest in using depleted oil and gas reservoirs for geological storage of CO_2 due to extensive preexisting geological characterization and infrastructure but the presence of a large number of well penetrations increases the possibility of leakage (Celia et al., 2005).

From a health and safety perspective, if large-scale leakage were to occur at the surface, asphyxiation and suffocation are of concern. Continued exposure to CO_2 concentrations above 20–30% is associated with suffocation to humans and most air-breathing animals (Damen et al., 2006). Since CO_2 is denser than air, topography and prevailing meteorologic conditions would largely govern risk from a large-scale release with gas buildup being greater in valleys and low-lying areas.

As discussed in Volume II of the DEIR (RDEIR, 2024b), in 2008 in Mönchengladbach, Germany, over 100 residents suffered from respiratory problems due to a CO_2 release, of which 19 were hospitalized. The incident involved the release of about 15 metric tons of fire suppression CO_2 inside a factory, which leaked out of the building. At the time there was no wind, so the dense CO_2 cloud drifted down hill to the lowest lying region where there was a village about 1,500 feet away (RDEIR, 2024b).

Probably the best-known anthropogenic release of CO_2 occurred in February 2020 from a CO_2 pipeline rupture in proximity to Satartia, MS. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld (RDEIR, 2024b). Pipeline operators are required to establish atmospheric models to prepare for emergencies. Denbury's model did not contemplate a release that could affect the Village of Satartia (RDEIR, 2024b). Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions (RDEIR, 2024b). Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release (RDEIR, 2024b). Denbury reported that 200 residents surrounding the rupture location were evacuated, and forty-five people were taken to the hospital. No fatalities were reported (PHMSA, 2022).

Following this incident, a large release of CO_2 to the atmosphere occurred later in 2020 in Yazoo County, Mississippi due to a blowdown valve freezing open (RDEIR, 2024b). Work was being conducted to reconnect the pipeline that had ruptured near Satartia. An 8-inch valve froze in the open position due to internal dry-ice formation as CO_2 flashed across the valve (RDEIR, 2024b). A total of approximately 5,299 metric tons of CO_2 were released over about 24 hours until the pipeline segment pressure had reduced enough to allow the valve to thaw and be closed. A large CO_2 cloud formed, and the nearby highway closed. Air monitoring was conducted in the surrounding area (RDEIR, 2024b).

A clearly unacceptable release from a wellbore would be a CO_2 well blowout. A CO_2 well blowout is considered a low probability high consequence incident (Oldenburg and Budnitz, 2016) that could cause an immediate danger to public health in the vicinity of an abandoned well. The Sheep Mountain CO_2 blowout in March 1982 is a well-documented case in the literature (GEM Wiki, 2024). The leakage rate was estimated to be 13,000 metric tons CO_2 per day (GEM Wiki, 2024). 100% CO_2 flow was observed in the well with chunks of dry ice occasionally ejected hundreds of feet into the air. Other examples of CO_2

well blowouts include the Travale geothermal field, Italy in 1972 having a CO_2 release rate of 113 kg/s and the Torre Alfina geothermal field, Italy in 1973 (Lewicki et al., 2007) having a CO_2 leakage release rate of 76 kg/s (Lewicki et al., 2007; Aines et al., 2009).

Another example of CO_2 release via a wellbore is Crystal Geyser in Utah (the largest cold geyser in the world). The geyser was unintentionally created in the 1930s after a prospective oil well was drilled about 2,600-foot-deep into a fault zone above a natural CO_2 reservoir (RDEIR, 2024b). Shortly after drilling, the well was improperly abandoned allowing CO_2 to be released through the well (RDEIR, 2024b). Crystal Geyser eruptions last from 7 to 98 minutes with a release rate between 2.5 and 6 kg/s. Downwind CO_2 concentrations have been measured during eruptions, averaging about 4,000 parts per million (ppm) (0.4 percent) at 160 feet, and 800 ppm at 330 feet (RDEIR, 2024b).

In 2011, an improperly plugged and abandoned well failed at the Tinsley Field, Mississippi during CO_2 enhanced oil recovery (EOR) (RDEIR, 2024b). There were incomplete records of abandoned wells at the site (RDEIR, 2024b). A 2,000-foot-deep well failed when the reservoir pressure increased on injection of CO_2. The blowout took 37 days to bring under control, sickened one worker and suffocated deer and other animals (RDEIR, 2024b).

In 2013, an underground CO_2 blowout occurred at the CO_2-EOR Delhi field in Louisiana, when two or more plugged and abandoned wells failed underground (RDEIR, 2024b). Methane, CO_2, oil, water, brine and sands migrated to the surface in a sparsely populated, marshy area. The release lasted for more than six weeks and contaminated the air with CO_2 and methane (RDEIR, 2024b).

Comment: As evidenced in the Satartia, MS CO_2 pipeline release and other documented incidences of CO_2 release, including those from wellbores, release of CO_2 from an injection well or failed plugged or unplugged wellbores could be catastrophic depending on surface topography and meteorologic conditions. In Volume I of the recirculated DEIR (RDEIR, 2024a), CTV states that the closest sensitive receptor to the project site is McKittrick Elementary School, which is 4.47 miles southwest of the facility pipeline and injection well 357-7R. The nearest residence is approximately 4.4 miles southeast of the injection line and 4.4 miles from injection well 345-36R. Buttonwillow Recreation and Park District is approximately 7 miles northeast of injection well 355-7R and 6.9 miles from the injection pipeline. Based on project-specific and site-specific considerations, the County should determine safe distance(s) for injection wells, wellbores, and pipelines from human receptors and adopt setback(s) that prohibit development at unsafe distance(s).

Comment: Another issue of concern is future development encroaching near land used for CO_2 storage. The land area containing wellbores and vicinity of this land area (e.g., within 1 mile) could conceivably not be suitable for public use for hundreds of years if not longer. In generations to come, it is conceivable that buildings or homes could be constructed overlying plugged well penetrations which could leak highly pressurized CO_2 into indoor air. The recirculated DEIR does not address restrictions on future land use.

Mineralization of Injected CO_2

In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that computational modeling indicates that CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is estimated to be 20% and 8% of the CO_2 injected, respectively. Hence, 72% of injected CO_2 is

expected to remain in a supercritical state for an extended period of time (e.g., thousands of years). In the A1 - A2 reservoir, CTV states that because of low water saturation within the Monterey Formation, greater than 98% of the CO_2 injectate will remain in a supercritical phase (RDEIR, 2024b). The phase (supercritical fluid, dissolved in water or oil) and form (mineralization) of CO_2 is important because storage as a supercritical fluid is the least secure phase of storage while formation of carbonates during mineralization is by far the most secure form of storage.

Comment: In Volume I of the original DEIR (DEIR, 2023a), CTV stated that full mineralization of CO_2 is expected to occur in two to five years - a gross misstatement. If this were true, there would be little concern with geological storage of CO_2 at the CTV facility. Research is ongoing in formations having high divalent cation concentrations (iron, calcium, magnesium) (e.g., basalt) where mineralization is much more rapid. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV appears to have revised its position and now states that based on previous studies on reactive transport modeling and geochemical reactions during geological storage, the amount of CO_2 predicted to be trapped by mineralization reactions at the TerraVault 1 Project is small over a 100-year post injection time frame. For this reason, CO_2 mineralization was not included as a part of the compositional simulation modeling. The importance of this discussion is the realization that at the TerraVault I facility, CO_2 will be stored primarily as a highly pressurized supercritical fluid (the least secure form of CO_2) and must be retained for hundreds if not thousands of years with little or no hope of transition of CO_2 to more stable forms of storage (e.g., dissolution, mineralization).

Lateral Confinement to Storage Areas

The Elk Hills Oil Field is a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide (RDEIR, 2024b). With increasing depth, the structure subdivides into three distinct anticlines, separated at depth by inactive high-angle reverse faults (RDEIR, 2024b). The project would be developed in two phases. In Phase 1, three new wells and one modified existing well used for enhanced oil recovery will be used to inject CO_2 into the Monterey Formation in the 26R reservoir portion of 31S anticline (RDEIR, 2024a). In Phase 2, two modified wells used for enhanced oil recovery would be used to inject CO_2 into the Monterey Formation in the A1 - A2 reservoir portion of the Northwest Stevens anticline (RDEIR, 2024a). CTV states that it plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir to ensure that CO_2 does not migrate beyond the edges of the anticline structure (RDEIR, 2024a).

Comment: The isolation of injected CO_2 in anticlinal structures is of concern. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that the Monterey Formation in the 26R and A1 - A2 storage reservoirs have "*minimal*" connection outside the Area of Review. The DEIR is vague about what this means for the project and lacks support for this assumption. Do anticlinal structures provide full containment or not? The 26R Reservoir is located within the 26R sands of the 31S anticline while the A1-A2 reservoir is located in the western portion of the Northwest Stevens (NWS) anticline. As discussed by Zumberge et al. (2005), the Northwest Stevens anticline and the 29R anticline share some of the same turbidite sand bodies (24Z and 26R sand bodies) (Figure 1). Also, the Northwest Stevens anticline shares the 26R sand body with the 31A anticline (Figure 1). After filling of the Northwest Stevens anticline reservoirs, oil appears to have spilled into and filled the 24Z trap (Figure 1). This same oil family may also have reached the 2B trap on the east nose of the 29R anticline and the 26R reservoir at the west end of the 31S anticline (Figure 1), again moving within turbidite sand bodies from the Northwest Stevens

(NWS) structure. It appears then that there is hydraulic communication between the Monterey Formation inside and outside of the 26R and A1 - A2 reservoirs and injection must be carefully managed to avoid migration of injected CO_2 outside of these reservoirs (exceedance of spill point). From schematics provided by CTV, there are a large number of wellbores screened in the Monterey Formation outside of storage areas (Figure 2). At least some of these wellbores should be converted to monitoring wells to monitor for both pressure perturbation and CO_2 leakage during injection.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that the Area of Review will be reevaluated if unexpected changes in fluid constituents or pressure outside the Monterey Formation 26R reservoir that are not related to well integrity are detected. The recirculated DEIR also states the Area of Review will be reevaluated if unexpected changes in fluid constituents or pressure outside the A1 – A2 reservoir that are not related to well integrity are detected. These statements are meaningless since there is no planned monitoring outside the 26R and A1 – A2 reservoirs.

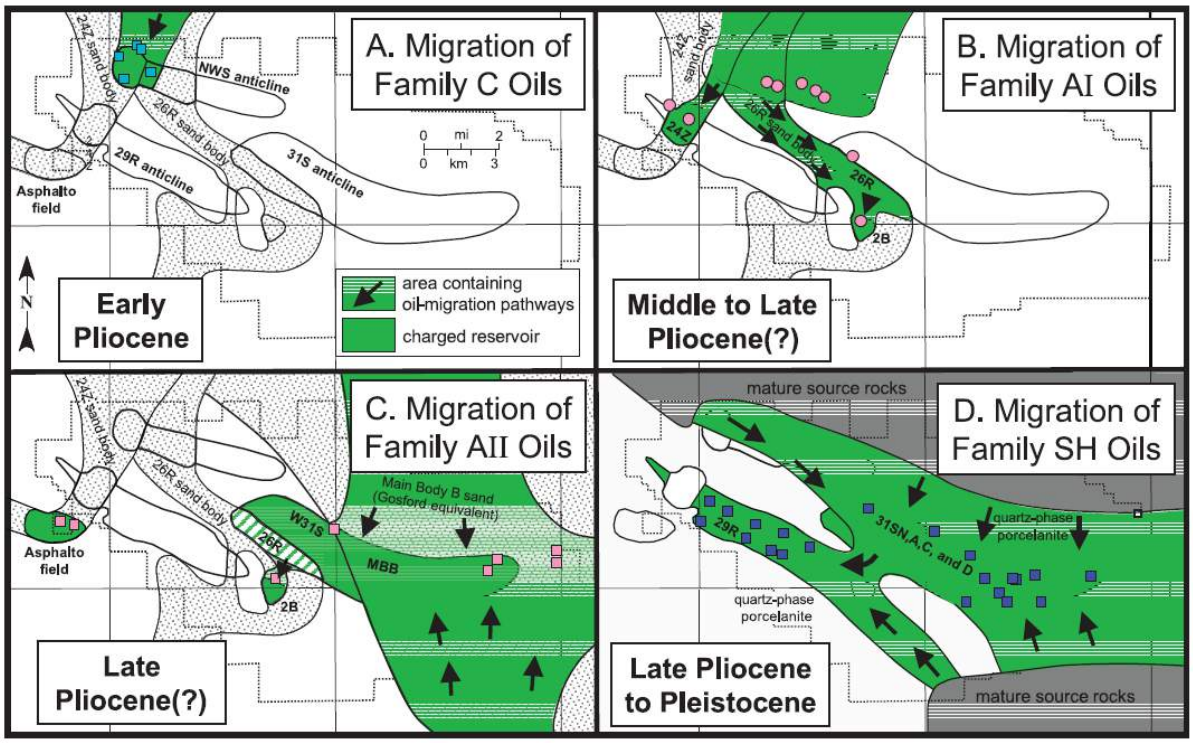


Figure 1. Migration of oil into major Stevens turbidite and porcelanite reservoirs at the Elk Hills Oil Field. (A) Family C oils are restricted to the western end of the Northwest Stevens anticline and are the least mature of the sampled oils. They may have migrated into the earliest formed traps in the Northwest Stevens anticline along turbidite sand bodies updip from the Buttonwillow subbasin. (B) Oils of family AI are likely derived from the Buttonwillow subbasin and filled reservoirs in the central and eastern Northwest Stevens anticline. Oil spilled from the Northwest Stevens traps and followed turbidite sand bodies updip into the 26R, 2B, and 24Z reservoirs. (C) Family AII oils probably are from both the Buttonwillow and Maricopa subbasins and migrated into the 31S reservoirs following the Main Body B submarine-fan complex. Oil possibly leaked into the 26R sand body and spilled into the 2B trap. The occurrence of family AII oil in the Asphalto field remains a dilemma. (D) Family SH oils occur in porcelanite reservoirs across the entire field and are sandwiched stratigraphically between families AI and

AII reservoirs. Migration likely occurred after filling of the turbidite reservoirs and after development of more favorable porosity because of transition of porcelanite from opal-CT to quartz phase. Figure from Zumberge et al. (2005).

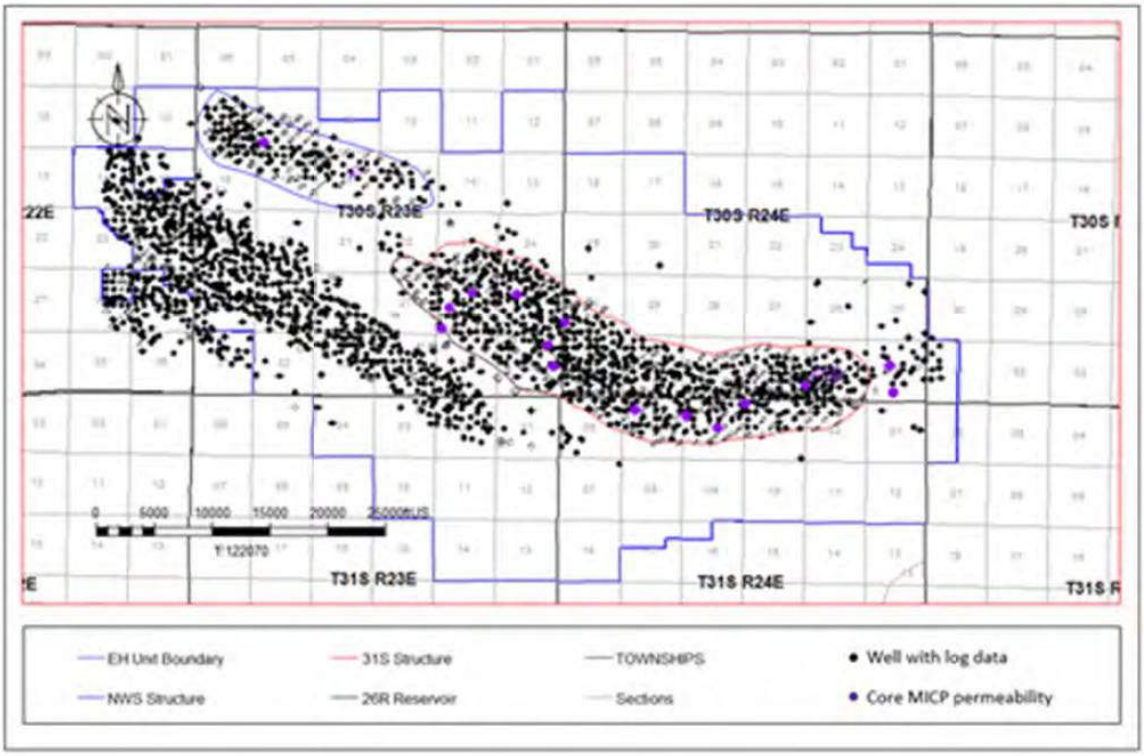


Figure 2. Wells drilled in the Elk Hills Oil Field (EHOF) that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core data from the Monterey Formation are shown in purple. Figure from Volume II of recirculated DEIR (RDEIR, 2024b). Note the poor resolution of the figure is due to poor resolution in the recirculated DEIR.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that confinement of the Reef Ridge Shale has been demonstrated in the 26R reservoir by the injection of 841 billion cubic feet of gas and 114 million barrels of water with no leakage. CTV states that confinement of the Reef Ridge Shale has been demonstrated in the A1 - A2 reservoir by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage. Referring to the work by Zumberge et al. (2005), CTV further states that geochemical analysis of reservoirs confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate (RDEIR, 2024b). However, as discussed in the previous comment, this geochemical analysis also confirmed migration of oil between anticlinal traps, which the DEIR does not discuss. More importantly, there is no evidence of how and if leakage was monitored. It does not appear that CRC used monitoring wells in the Monterey Formation outside the 26R and A1 - A2 reservoir areas to evaluate migration of injected fluids beyond anticlinal structures associated with these formations. It also does not appear that CRC monitored oil and gas wells for gas leakage during enhanced oil recovery operations. Hence, the veracity of these claims cannot be independently verified, and they are not supported by arguments provided. Again, CTV should

convert several existing oil and gas wells screened in the Monterey Formation outside storage reservoirs into additional monitoring wells.

Permanence Criteria

The primary purpose of geological storage of CO_2 is mitigation of climate change. Leakage of CO_2 from a storage formation through wellbores will occur to at least some extent (Celia and Bachu, 2003). Hence, the important question is not whether there will be leakage, but whether the extent of leakage is acceptable (Celia and Bachu, 2003) and how leakage will be monitored and quantitated.

A leakage rate of less than 1% to the atmosphere over 1,000 years is necessary for geological storage of CO_2 to achieve the same climate benefits as renewable energy sources (Shaffer, 2010). This metric for effective storage is more stringent than that of Hepple and Benson (2005) who considered leakage over a shorter time frame and concluded that leak rates of 0.01% per year to the atmosphere, equivalent to 99% retention of the stored CO_2 after 100 years, may be adequate to ensure the effectiveness of CO_2 storage.

In a Special Report on Carbon Dioxide Capture and Storage, the Intergovernmental Panel on Climate Change (IPCC, 2005) stated that for a well selected, designed, operated and appropriately monitored system, the balance of available evidence suggests that it is very likely the fraction of stored CO_2 retained is more than 99% over the first 100 years and it is likely the fraction of stored CO_2 retained is more than 99% over the first 1,000 years.

To assess the risk of leakage of CO_2 through wellbores, Callas et al. (2022) used a storage security calculator developed by Alcalde et al. (2018) to estimate the percent of CO_2 leaked for different densities of wells per square kilometer (km) in a well-regulated environment. Callas et al. (2022) determined that a well density greater than 8 wells/km^2 would result in more than 1% cumulative CO_2 leaked in 1,000 years in a well-regulated environment. They categorize the density of existing or abandoned wells as >8 wells/km^2, 6–7 wells/km^2, 4–5 wells/km^2, 2–3 wells/km^2, and <1 well/km^2 as worst to best for wellbore leakage concerns. Given the presence of 354 well penetrations (204 in 26R reservoir and 150 in A1 - A2 reservoir) through the confining layer and a total storage area of 9,104 acres (36.85 km^2) (RDEIR, 2024a), a well penetration density of 9.6 wells/km^2 represents a worst-case scenario for permanence for geologic storage of CO_2. The presence of a large number of well penetrations necessitates a robust evaluation of wellbore integrity of both plugged and unplugged wells prior to injection and raises serious concerns about the permanence of storage in the 26R and A1- A2 reservoirs.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV stated that computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration after cessation of injection in the A1 - A2 reservoir.

A pressure loss of 10 psi per year is not negligible. A simple back of the envelope calculation indicates that a pressure loss of 10 psi per year starting at 4000 psi (final target pressure) results in complete pressure loss in 400 years (Figure 3) resulting in appreciable CO_2 loss. In reality, the rate of pressure loss will decrease somewhat as pressure decreases in the formation (i.e., reduction in driving force) as illustrated in loss in percent per year (Figure 3). This metric of leakage verification is not sufficiently protective and should be rejected. A target of 0.01% pressure loss per year is more reasonable if permanent storage of CO_2 is actually the goal of this project.

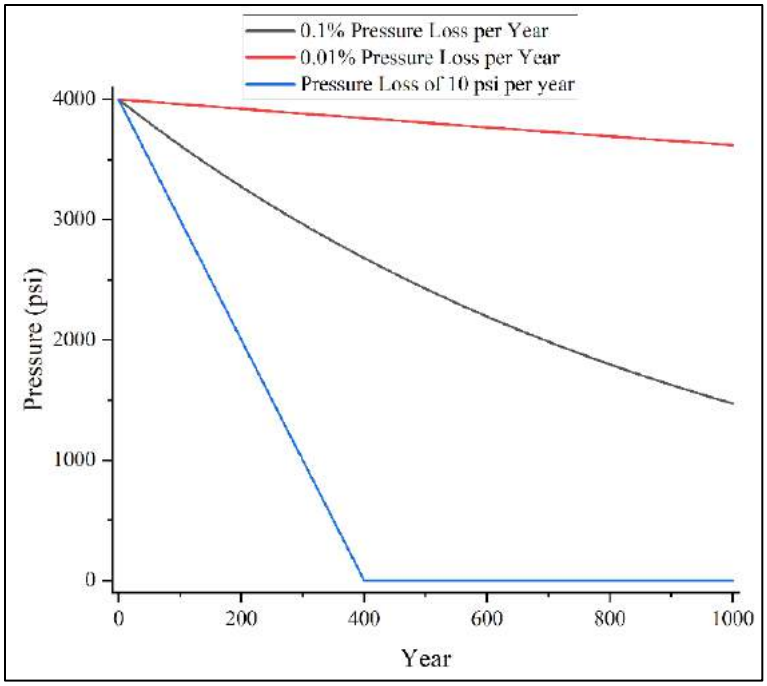


Figure 3. Simulation of 10% pressure loss per year, 0.1% pressure loss per year, and 0.01% pressure loss per year for 1000 years starting at 4000 psi.

Comment: A permanence standard should be established in the recirculated DEIR to determine the effectiveness and impact of the project. In the absence of a permanence standard, there is no metric to determine whether CO_2 is permanently retained. As part of an application for Sequestration Site Certification to receive tax credits, the California Air Resources Board (CARB) requires a greater than 90% probability of occurrence that 99% of CO_2 will be retained in the *"storage complex"* over 100 years post-injection to be eligible to receive Permanence Certification required for operation in California (CARB, 2018). CARB defines a *"storage complex"* as a *"three-dimensional subsurface volume that is characterized, modified by corrective actions, and monitored so that the CCS Project is able to meet the requirements for carbon sequestration under the Permanence requirements…For saline and depleted oil and gas reservoirs, the storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume, which is expected to contain the CO_2, and overlying and possibly underlying geologic formations that are required to provide assurance of storage. The storage complex must include a multilayered confining system that retards vertical migration of CO_2. The storage complex must extend laterally over (1) the volume from which CO_2 (as a free or dissolved phase) could escape from storage in the subsurface if a permeable pathway exists, and (2) the area over which the plume may migrate."* Hence, for the TerraVault I project, the storage complex would include the Etchegoin Formation. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV refers to the Etchegoin Formation as a *"dissipation interval."* or an allowable zone for migration from the storage formation. However, in the Class VI permit applications for the 26R Reservoir, EPA states that *"The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a)."* There is no allowance or tolerance for leakage outside the storage reservoirs and leakage into the Etchegoin Formation constitutes the movement of fluids into an unauthorized zone. Hence, in EPA regulations, there is no concept of a storage complex and a permanence

standard must be framed in terms of leakage from a storage formation. It is recommended for this project that a permanence criterion be specified as a 95% probability of occurrence that 99% of CO_2 will be retained in the 26R and A1 - A2 reservoirs over a period of 100 years. Based on the research of Shaffer (2010), a criterion for leakage to the atmosphere should be specified as a 95% probability of occurrence that 99% of CO_2 will be retained within all subsurface media over a period of 1,000 years.

Comment: Information presented in Volume II of the recirculated DEIR (RDEIR, 2024b) does not support a finding that the project will have greater than 95% probability that 99% of CO_2 will be retained in the storage reservoirs over a period of 100 years or even a 90% probability that 99% of CO_2 will be retained in a "*storage complex*" over a period of 100 years as required by CARB for tax credits. These retention findings are not credible because: (1) the large number of wellbores (354) penetrating the Reef Ridge Shale serving as primary pathways for leakage, (2) the high pressure (~4,000 psi) (the driving force for leakage) of storage, (3) storage occurring primarily as a separate phase of supercritical fluid resulting in direct contact of supercritical CO_2 with all 354 well penetrations, and (4) the high probability of elevated magnitude seismic activity in the vicinity of the project area capable of inducing levels of peak ground acceleration that would likely induce wellbore damage after plugging. These issues are discussed in more detail below.

Comment: In Volume I of the recirculated DEIR (RDEIR, 2024a), Impact statement 4.8-1 (Generate Greenhouse Gas Emissions, Either Directly or Indirectly, that may have a Significant Impact on the Environment), the level of significance before mitigation is categorized as potentially significant (RDEIR, 2024a). In mitigation measure MM 4.8-1, CTV states that "*Prior to any injection of CO_2 the owner/operator shall submit a monitoring plan that complies with all requirements of the EPA UIC permit issued for the project to demonstrate the retention of CO_2 in the injection/hydrocarbon reservoir zone. The plan shall be submitted to the Kern County Planning and Natural Resources Department concurrent with submittal to the EPA for review. A copy of the final approved plan from the EPA shall be provided to the Kern County Planning and Natural Resources Department"* (RDEIR, 2024a). The monitoring plan submitted in Volume II of the recirculated DEIR does not directly (e.g., soil-gas monitoring) consider leakage from well penetrations – the most likely source of loss of retention of CO_2. Hence, MM 4.8-1 is deficient and should be rejected. It will be necessary to combine continuous areal monitoring of leakage with periodic monitoring of individual well penetrations to ensure retention of CO_2 and to quantify leakage.

Emergency and Remedial Response Plans

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1 - A2 reservoirs, CTV outlines emergency and remedial steps to be taken in the event of impact to an Underground Source of Drinking Water (USDW) but argues earlier in the document that no USDWs exist at the 26R and A1 - A2 reservoirs because of an aquifer exemption. In this section, CTV should substitute the term USDW with Lower Tulare Formation.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1 - A2 reservoirs, CTV outlines steps to be taken in the event of well integrity failure. These steps are limited to injection wells. The Emergency and Remedial Response Plan for both the 26R and A1 - A2 reservoirs should include consideration for well integrity loss in monitoring

wells and plugged abandoned wells. For the A1 - A2 reservoir, unplugged wells used for injection in the A3 - A11 reservoir should also be considered.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1 - A2 reservoirs, CTV discussed venting CO_2 from surface facilities in the event of an emergency. There is no discussion how loss of CO_2 will be quantified during venting.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1- A2 reservoirs, CTV does not directly address steps to be taken in the event of leakage into the Lower Etchegoin Formation. Instead, when addressing release into the overlying USDW, CTV states that *"Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale [will be used] to establish leakage before migration to USDW."* At a minimum, leakage into the Lower Etchegoin Formation as determined by pressure perturbation or sample analysis should trigger installation of additional monitoring wells in this formation to evaluate the magnitude and spatial extent of leakage. As previously discussed, in the Class VI permit applications for the 26R Reservoir, EPA states that *"The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a)."* The Etchegoin Formation is not purposeful "*dissipation interval*." Leakage into the Etchegoin Formation constitutes the movement of fluids into an unauthorized zone. Hence, detection of leakage into this zone should necessitate installation of additional monitoring wells and development of a separate monitoring plan for this formation.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) for the A1 - A2 reservoir, CTV states that in case of an induced seismic event having **M** > 2.0, it will initiate gradual shutdown of the injection wells if it is determined "*appropriate.*" The word "*appropriate*" is vague and does not provide a measurable performance criterion per CEQA requirements. After initially using the word *"appropriate"* in Volume II of the original DEIR for the 26R reservoir (DEIR, 2023b), in Volume II of the recirculated DEIR (RDEIR, 2024b), CTV now states that for induced seismic events having **M** > 2.0, that it will initiate a "rate reduction plan" in the 26R reservoir. Why is there an inconsistency here? A rate reduction plan is clearly more appropriate.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) for both the 26R and the A1 - A2 reservoirs, CTV states that shutdown will not be initiated unless a seismic event greater than **M** 3.5 has occurred or a seismic event having **M** > 2.0 accompanied by local observation or report of damage. CTV defines the onset of damage as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets. CTV states that it will monitor well pressure, temperature, and annulus pressure of injection wells to verify well status and determine the cause and extent of any failure, and identify and implement appropriate remedial actions in consultation with the UIC Program Director. There is no mention of evaluation of any other wellbores - a critical oversight. This response action is also inconsistent with CARB requirements. The CARB protocol for CO_2 sequestration requires that the operator continuously monitor for indication of an earthquake of **M** 2.7 or greater occurring within a radius of one-mile of injection operations. If an earthquake of **M** 2.7 or greater is identified, CARB, in consultation with the project operator and the California Geological Survey, or local geological survey or equivalent, must conduct an evaluation of the following: (a) whether there is indication of a causal connection between the injection activity and the earthquake; (b) whether there is a pattern of seismic activity in the area that correlates with nearby injection activity; and (c)

whether the mechanical integrity of any well, facility, or pipeline within the radius specified in subsection C.4.3.2.3(b) has been compromised (CARB, 2018). Hence, if induced seismicity having a magnitude of **M** 2.7 or larger occurs, the operator must conduct an evaluation of the integrity of all wellbores including those plugged and abandoned.

Evaluation of Well Penetrations from Legacy Oil and Gas Wells

As EPA states in the Class VI permit applications for the injection wells for the 26R reservoir, *"the permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a)"* (EPA, 2024). Hence, even in the absence of a USDW in the 26R and A1 - A2 reservoirs, as a result of an aquifer exemption, the permittee cannot allow migration of CO_2 or other fluids (brine, oil) into overlying or underlying formations.

In 40 CFR 146.84(c)(2), EPA states, *"Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require."* In 40 CFR 146.84(c)(3), EPA states *"Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream."* In 40 CFR 146.84(d), EPA states, *"Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate."*

Federal requirements for evaluation of legacy oil and gas wells essentially consist of providing a tabulation of wells penetrating the primary confining layer and a subjective evaluation that plugged legacy wells and wells that will be plugged will not provide a conduit for leakage. These minimal requirements are in sharp contrast to specific internal and external mechanical integrity tests required for injection wells even though legacy wells will be directly exposed to supercritical CO_2 similar to injection wells.

However, in its guidance document on Area of Review and Corrective Action, EPA (EPA, 2013) provides an extensive set of recommendations for evaluation of artificial penetrations. Evaluation commences with review of available information including drilling logs, well completion and plugging reports, casing and cementing records, records on internal and external mechanical integrity tests, cement bond/variable density logs, information on well deviation, and wellbore diagrams (EPA, 2013). EPA states that if available records cannot establish wellbore integrity prior to plugging (e.g., corrosion in well casing and competent cement outside casing at critical locations such as at the interface of the injection zone and confining layer), additional testing is recommended (EPA, 2013). Additional testing could include multi-finger caliper logging, cement evaluation logging, internal and external mechanical integrity testing, and sidewall coring (EPA, 2013).

Logically, additional testing should include testing for sustained casing pressure and surface casing vent flows which are indicators of wellbore integrity failures and increase the potential for gas emissions and groundwater contamination (Ingraffea et al., 2014, 2020; Lackey and Rajaram, 2019; Soares et al., 2021). Leak testing using procedures developed by Kang et al. (2016) could also be utilized to evaluate well integrity.

Wellbore integrity failure is common. Rates of wellbore integrity failure range from 2 to 75% (Davies et al., 2014). Recent analysis of state and provincial databases show that wellbore integrity issues are widespread in oil and gas well populations in Canada and the U.S. and are likely under-reported or not reported at all depending on the jurisdiction (Wisen et al., 2020; Lackey et al., 2021; Ingraffea et al., 2014, 2020; Abboud et al., 2021).

Wellbore integrity failures are not necessarily addressed through well plugging and can persist after the well is "properly" plugged (Bowman et al., 2023; Kang et al., 2021; Wisen et al., 2020). Surface casing vent flow or sustained casing pressure in an oil or gas well may be due to annular gas flow which may not have been properly addressed during plugging. Importantly, regulations for plugging oil and gas wells in California do not require assessment of the cement sheath outside casing. Hence, gas flow in the annulus outside casing will persist after plugging.

For instance, DiGiulio et al. (2023) found that approximately 9 of 27 (33%) of plugged oil and gas wells were leaking gas through vent pipes at the surface and 3 of 26 (10%) of plugged wells examined were leaking gas through soil at the surface in western Pennsylvania, clearly demonstrating that oil and gas wells can and do leak gas after plugging. Kang et al. (2016, 2017) and DiGiulio et al. (2023) found mean emission rates of leakage of methane from plugged wells in western Pennsylvania were 360 and 390 g/d, respectively. However, the computation of the mean emission rate from plugged wells in the dataset from DiGiulio et al. (2023) excluded an outlier, a plugged well leaking at a rate of 83 kg/d. It is important to realize that these rates are from depleted oil and gas fields. Higher emission rates of gas (in this case CO_2) would be expected if reservoirs were repressurized as is the case for geological storage of CO_2 in depleted oil and gas fields such as at the TerraVault I Project. DiGiulio et al. (2023) and other investigators have found that emission rates from both unplugged and plugged oil and gas wells follow a distribution whereby leakage from a relatively small number of wells accounts for the majority of total leakage. It is plausible, if not likely, that leakage of CO_2 from abandoned wells will follow a similar distribution.

Addressing gas migration via the annulus outside casing requires treatments such as cement squeezes and casing repair (Hachem et al., 2023; Ingraffea et al., 2014; Yousuf et al., 2021). However, the process of investigation and then remediating annular gas leakage is more complex and expensive than the average plugging procedure (Raimi et al., 2021) whereby plugs are simply placed inside casing, as will be the case at the TerraVault I project.

Comment: Neither the State of California nor EPA in its Class VI regulations require investigation or remediation of the cement sheath outside casing prior to plugging legacy oil and gas wells within the Area of Review to support geological sequestration of CO_2. Because these plugged wells at TerraVault I are expected to contain highly pressurized supercritical CO_2 for hundreds if not thousands of years, the County should not ignore the serious gaps in the existing regulatory framework and must require full investigation and remediation.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that there are 150 wellbores in the A1 - A2 storage reservoir penetrating the Reef Ridge shale. There are 41 active, 70 idle, and 39 plugged and abandoned wells. Of active and idle wells, 79 wellbores produce oil and gas while 32 wellbores are used for gas or water injection. CTV states further that 33 wells in the A1 - A2 have been identified for abandonment. Since there are 79 currently unplugged wellbores, 3 wellbores that will be reconfigured for injection, and 3 wellbores that will be reconfigured as monitoring wells, what is the status of the remaining 40 wellbores? How many of these wellbores will be used for continued production in the underlying A3 - A11 reservoir? The RDEIR should account for these wells.

Comment: The recirculated DEIR is replete with vague terms that lack definitions and measurable standards. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that in the A1 - A2 reservoir, all wells within the Area of Review are protective of the USDW because there is *"sufficient"* annular cement within the confining Reef Ridge Shale. What precisely does *"sufficient"* mean? The word *"sufficient"* is vague and does not provide a measurable performance criteria per CEQA requirements. Does cement in the annulus cover the entire extent of the Reef Ridge Shale? How was the integrity of the cement evaluated? What standards were utilized?

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), Appendix 1 for the A1 - A2 reservoir (page 3421) does not have a column on evaluation of annular cement in the 20-foot A2 shale between the A1- A2 reservoir and A3 - A11 reservoir. CTV states that all wellbores in the A1 - A2 reservoir that are not planned for abandonment have been determined to be "*adequately*" isolated from A1-A2 sands. What precisely does *"adequate"* mean? The word *"adequate"* is vague and does not provide a measurable performance criteria per CEQA requirements. Does annular cement extend completely through the A2 shale? How was the integrity of the cement evaluated?

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), appendices (page 3221 for the 26R reservoir and page 3421 for the A1 – A2 reservoir) provide a tabulation of wells by well name, API number, wellbore type (producer, injector, abandoned), wellbore status (active, idle, plugged), date drilled, surface latitude, surface longitude, wellbore total measured depth, wellbore total vertical depth, well construction method (vertical cased cemented, directional cased cemented, original hole cased cemented with sidetrack, sidetrack - open hole with sidetrack, sidetrack - directional cased cemented), completion record within injection zone (open, not opened, abandoned, isolated), USDW isolation (no USDW), annular isolation within injection zone (adequate, adequate with P&A, no annulus, not drilled to injection zone, plug/isolation within the injection zone (adequate, adequate with P&A, unplugged), plug/isolation within the upper confining layer (adequate, adequate with P&A, unplugged), pre-operational testing requirement (none, abandon, convert to monitoring well), corrective action requirement (none). A number of descriptors in this appendix are confusing. For instance, while the term sidetrack is generally understood, what does "sidetrack - open hole with sidetrack" and "sidetrack - directional cased cemented" mean? Example diagrams of each well construction method should be provided to facilitate transparent review and full participation by the public and expert agencies. For completion record within the injection zone, it is not clear what "not opened and isolated" means. Again, each descriptor should have some sort of explanation.

Comment: In these appendices, what does *"adequate"* annular isolation within the injection zone mean? The word *"adequate"* is vague and does not provide a measurable performance criteria per CEQA

requirements. Does this mean that there is cement outside casing at these locations? It is unclear how this could be the case for wells completed in the 26R reservoir.

Comment: In these appendices, what does *"adequate"* with P&A mean for these wellbores? Again, the word *"adequate"* is vague and does not provide a measurable performance criteria per CEQA requirements. Importantly, for plug/isolation within the injection, for plugged wells, does *"adequate"* mean that a cement is placed across the entire production interval and > 100 feet into the Reef Ridge Shale by CalGEM regulations? If this is not the case, plugs within these wellbores should not be considered *"adequate"* and at least potentially necessitate corrective action. For plug/isolation within upper confining layer, does *"adequate"* mean that a competent cement sheath outside casing extends entirely through the Reef Ridge Shale? How would "competent" be defined? Use of cement bond/variable density logs conducted shortly after well completion are not representative of current conditions, especially in injection wells with countless pressure cycles which are known to debond cement from casing and cause microannuli.

Comment: Wellbore schematics are absolutely vital in understanding the need or potential need for corrective action. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that the corrective action assessment included the generation of detailed wellbore/casing diagrams for each wellbore. The wellbore diagrams include depths and dimensions of all hole sections, casing strings, cement plugs and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are apparently described with depth and status of perforations. Top of Cement determination results were apparently provided to support review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. CTV states further that the depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. CTV then states that CTV can demonstrate that the USDW is protected and that, with well abandonment and monitoring, the CO_2 injected will be confined to the Monterey Formation 26R reservoir. CTV has claimed that these wellbore schematics are business confidential information. Unfortunately, the EPA agreed with CTV that disclosing the wellbore diagrams *"would result in reasonably foreseeable harm to the Company's commercial interests"* (EPA, 2024b). It is difficult to reconcile this statement with the fact that wellbore diagrams are commonly publicly posted on state oil and gas internet sites (e.g., Wyoming Oil and Gas Commission). This unjustified lack of transparency can and indeed should erode public confidence in this project. In addition to wellbore diagrams, CTV should make all information associated with wellbores relevant to wellbore integrity publicly available (e.g., internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc.). Information on plugging locations now provided in Appendix 2 in the recirculated DEIR is not a substitute for wellbore schematics.

Comment: In the recirculated DEIR, CTV identified 204 wellbores in the 26R reservoir and 150 wellbores in the A1 - A2 reservoirs (RDEIR, 2024b). No wellbores were deemed deficient in either reservoir and none require corrective action, according to the document. This 0.0% wellbore barrier failure rate for 354 wellbores is at odds with the published rates of wellbore failure rates ranging from 2 - 75% in the literature. Since no information (sustained casing pressure, surface casing vent flow, gas migration in soil, internal and external mechanical integrity testing, cement evaluation logs, wellbore diagrams, drilling logs, etc.) was provided, it is impossible to verify the accuracy of this statement, which

should be regarded with a considerable degree of skepticism. Did Kern County or EPA actually conduct an independent evaluation of wellbore integrity of each well penetration? A statement of no wellbore barrier failure cannot be accepted without supporting information. Again, all supporting information (wellbore diagrams, cement evaluation logs, internal and external mechanical integrity tests, etc.) should immediately be made available to the public to enable an independent evaluation of wellbore integrity.

Comment: In Volume II of the recirculated DEIR, CTV states that, "all wellbores within the AoR will, *if necessary*, be mechanically pressure tested, abandoned, reabandoned, monitored or have a technical demonstration showing *adequate* zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased scheduled post CO_2 injection if conditions allow." Again, the words *"if necessary"* and *"adequate"* are vague and do not provide a measurable performance criteria per CEQA requirements. It is unclear what conditions would preclude pressure testing. Since all wellbores penetrating the confining layer will be in direct contact with supercritical CO_2 at high pressure, prior to plugging, all wellbores should have a standard annular pressure test (SAPT) in casing above and between screened intervals to evaluate the integrity of casing as will be conducted for injection and monitoring wells. All testing factors should be similar to what is specified for monitoring wells: Testing surface pressure should be 1000 psi, isolation of pressure should be maintained for no less than one hour, and if the change (gain or loss) in pressure is greater than 3% of test pressure, the well has failed to demonstrate internal mechanical integrity. It is unclear what happens if a well fails a SAPT. Will the well be entered to investigate parted or corroded casing? Also, what is a demonstration of *"adequate zonal confinement"?* To evaluate the cement sheath outside casing, a cement evaluation log should be conducted on all wellbores prior to plugging. Statements in the Corrective Action Plan are too vague to be of any use. Hence, the Corrective Action Plan is unacceptable. Under CEQA, all feasible mitigation is required. The terms of the Corrective Action Plan do not constitute all feasible mitigation.

Comment: In Volume II of the recirculated DEIR, CTV states that the Etchegoin Formation consists of a lower silty shale member and an upper sandy interval. The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below. The Etchegoin Formation is dominated by laterally continuous shales which limit hydraulic communication between sand lenses. In the recirculated DEIR, CTV states that the Etchegoin Formation will dissipate CO_2 injectate that may migrate upward from the injection zone. According to the recirculated DEIR, in both the 26R and A1 - A2 reservoirs, the Etchegoin will be monitored continuously for pressure and temperature changes using one monitoring well to provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin (via DTS). In both areas, CTV states that a monitoring well in the Etchegoin Formation will continuously measure pressure and temperature providing continuous direct measurements to assess the confinement of the injected CO_2 and provide adequate spatial coverage across the Area of Review to evaluate confinement of CO_2 in the storage reservoir. One monitoring well in each reservoir cannot provide adequate coverage. Heterogeneity as described above will affect detection of increase in pressure during leakage. The presence of shale lenses will likely dramatically affect measurement of pressure in the Etchegoin Formation. CTV needs to stipulate the minimum magnitude of leakage that would be detected from pressure perturbation from the injection well located at the greatest distance from each monitoring well. CTV needs to justify the existence of only one monitoring well in the Etchegoin Formation.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2023b), CTV states that a laterally continuous 20-foot thick A2 shale having an average permeability of 0.05 millidarcies separates the A1 - A2 and underlying A3 - A11 reservoirs. This is in comparison to the Reef Ridge shale overlying the A1 - A2 reservoir having an average thickness of 1,555 feet and an average permeability of 0.0084 millidarcies. The A3 - A11 reservoir is currently undergoing waterflooding which will continue during injection of CO_2 into the A1 - A2 reservoir. CTV states that the A1 - A2 reservoir is hydraulically isolated from the A3 - A11 reservoir because: (1) the A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected) and (2) the Monterey Formation A1 - A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. CTV states that it will monitor the Monterey Formation A3 - A11 reservoir and wellbores for CO_2 migration from the A1 - A2 reservoir. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3 - A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests to ensure internal and external mechanical integrity. Additionally, in one portion of the recirculated DEIR, CTV states that due to its waterflood infrastructure and high reservoir pressure, the A3 - A6 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery. In another portion of the recirculated DEIR, CTV states that due to its waterflood infrastructure and high reservoir pressure, the A3 - A11 reservoir is considered a viable future target for CO_2 miscible enhanced oil recovery. It is not clear where the A3 - A6 reservoir is located or if it even exists. Since pressure in the overlying A1 - A2 reservoir will have a much higher pressure during CO_2 injection, migration through the thin A2 shale and wellbores penetrating the A2 shale constitute a major potential leakage pathway. Leakage into the A3 - A11 reservoir would constitute loss of containment.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines, will be conducted using eddy covariance towers. In regard to leakage to the atmosphere, under 40 CFR Part 98 Subpart RR, an operator must submit a proposed monitoring, reporting, and verification (MRV) plan to EPA within 180 days of receiving a final Class VI permit (§98.448(b)(2)). As part of the MRV plan, the operator must: (1) "identify potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways" (§98.448(b)(2)); (2) develop "a strategy for detecting and quantifying any surface leakage of CO_2" (§98.448(b)(3)); and (3) develop "a strategy for establishing the expected baselines for monitoring CO_2 surface leakage" (§98.448(b)(4)). Hence, leakage to the atmosphere will be considered at some point. However, a monitoring program should be specific to evaluating leakage from plugged well penetrations as general air monitoring may not be sufficiently sensitive to determine leakage. It is unclear what the magnitude of leak detection from plugged and unplugged wells would be from eddy covariance towers and whether eddy covariance towers would provide comprehensive coverage of all well penetrations. MM 4.8-1 needs to include specific monitoring for leakage from plugged and unplugged well penetrations. Methods employed by Kang et al. (2016) can be used for CO_2 monitoring at both plugged and unplugged wells.

Seismic Risk Evaluation

Of particular concern at the TerraVault I project is the effect of natural or induced seismicity on wellbores. After a well is permanently plugged and abandoned, natural or induced seismicity can damage wellbores. For example, hundreds of oil well casings were sheared in the Wilmington oil field in Los Angeles during

five or six earthquakes of relatively low seismic moment magnitude (**M** 2 to **M** 4) during a period of maximum subsidence in the 1950s (Dusseault et al., 2001). The seismic moment magnitude is the product of the area of rupture, the average displacement on the fault (a fracture or zone of fracture between two blocks of rock), and the shear modulus, a parameter related to the rigidity of rocks in the fault zone measured on a logarithmic scale (GWPC, 2021). Recently, Pozzobon et al. (2023) documented increased leakage of gas from plugged oil and gas wells resulting from seismic activity due to injection of produced water into disposal wells and hydraulic fracturing.

Impacts of earthquakes on buildings and pipelines, including those that are buried, have long been an active area of civil engineering research. There are empirical estimates of pipeline damage that relate the number of repairs to peak ground acceleration, peak ground velocity, maximum ground strain, and other factors. There is a need to extend this existing body of research to subsurface wellbore leakage caused by earthquakes (Kang et al., 2019), especially in regard to geological storage of CO_2.

USEPA's Class VI regulations require permit applicants to provide a determination that seismic activity will not compromise subsurface containment of injected carbon dioxide (40 CFR 146.82(a)(3)(v)). The Class VI rule provisions do not address potential damage to buildings and infrastructure (including wellbore cement sheaths of active and abandoned wells) associated with geologic storage of CO_2. However, as part of its permanence requirements for geologic sequestration, the California Air Resources Board (CARB) has developed requirements which include consideration of natural and induced seismicity (CARB, 2018). In the California Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CARB, 2018), if an earthquake of $\mathbf{M} \geq 2.7$ is detected within a radius of one mile of CO_2 injection operations, a determination must be made whether the mechanical integrity of any well, facility, or pipeline within this radius has been compromised. This protocol however does not consider a naturally occurring major seismic event at distance from an injection well which could induce ground movement damaging wellbores. In addition, the California Energy Commission has developed guidelines to evaluate the potential for induced seismicity during geological storage of CO_2 (CEC, 2017).

Given uncertainty in potential impact due to natural and induced seismicity during geological storage of CO_2, protocols developed by U.S. Department of Energy's (DOE) Recommended Practices for Managing Induced Seismicity Risk Associated with Geologic Carbon Storage (Templeton et al., 2021, 2023) should be used when permitting a facility for geological storage of CO_2. This integrated and risk-based protocol is a product of the DOE's National Risk Assessment Partnership, a multi-year collaborative research effort of Los Alamos National Laboratory, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, National Energy Technology Laboratory, and Pacific Northwest National Laboratory. This protocol specifically addresses the risk of seismicity at a geologic carbon storage facility and is relevant to CO_2 injection at Carbon TerraVault I. Recommendations by Templeton et al. (2021, 2023) and regulatory requirements and guidelines by EPA and the State of California are used here as the basis of evaluation for the seismicity portion of the permit application.

Review of Applicable Local, State, and Federal Laws and Requirements on Seismicity

Relevant local, state, and federal laws and regulations should be reviewed to determine how induced seismicity, however minor or unlikely, is regulated and its effects prevented or mitigated (Templeton et al., 2021). In California, the Alquist-Priolo Earthquake Fault Zoning Act (1972) and the Seismic Hazards Mapping Act (1990) direct the State Geologist to delineate regulatory "Zones of Required Investigation"

to reduce the threat to public health and safety and to minimize the loss of life and property posed by earthquake-triggered ground failures and other hazards. Cities and counties affected by the zones must regulate certain development projects within them, based on the CA CGS Information Warehouse: Regulatory Map Portal (https://maps.conservation.ca.gov/cgs/informationwarehouse/regulatorymaps/). As stated in the recirculated DEIR, the Carbon TerraVault I project does not appear to be within a Zone of Required Investigation. Kern County reviewed compliance with other applicable laws and regulations for this project in the document.

Review of Naturally Occurring Seismic Events and Delineation of a Region of Concern

To support a Class VI rule application, an owner/operator is required to submit a narrative description and information on the seismic history of the area, including the presence and depths of seismic sources, and a determination that seismicity will not interfere with containment of injected carbon dioxide (40 CFR 146.82(a)(3)(v)).

CARB requires an evaluation of the seismic history of the proposed sequestration site, including the date, magnitude, depth, and location of the epicenter of seismic sources and a determination that the seismicity would not cause a catastrophic loss of containment, either by breaching the integrity of the well or the sequestration formation (CARB 2018).

To evaluate the impact of a major naturally occurring seismic event distant from a site on a site, it is necessary to define a Region of Concern (ROC). The ROC is defined as the area in which a ground motion threshold over the lifetime of a project could be exceeded causing impact to infrastructure (Templeton et al., 2021), which in this case includes wellbores. An assessment or literature search should identify any tectonic events that may have occurred in the region and a map and catalog should be created for seismic events which have occurred within at least 200 km from the reservoir (Templeton et al., 2021).

Previous seismic activity should be characterized within a region of at least 200 km radius around planned injection operations to ensure that wider regional trends are considered in the seismic hazard assessment (Templeton et al., 2021, 2023). This consideration reduces the possibility of overlooking infrequent but possibly large events that could impact the local hazard. Elements of the seismicity characterization should include:

- Catalogs of instrumentally recorded earthquakes from national, state, or regional agencies.
- Historical records of earthquakes and observed fault ruptures, including but not limited to, historical earthquake catalogs, and newspaper and other contemporary records, and published reports of field geological investigations. Historic reports of significant earthquakes can provide important information on time periods that predate instrumental recording. For rare events that occur once every few hundred to thousands of years, this may be the only evidence of seismic activity.
- Fault maps and fault characterizations, including but not limited to, scientific maps and publications.
- Paleoseismic fault displacement data, including but not limited to, published trenching studies.
- Previous induced earthquake activity, including but not limited to, earthquake catalogs and scientific publications investigating possible induced activity. If the targeted region has a history of induced seismicity, this would be a strong indication of a critically stressed crust.

In Volume II of the original DEIR (2023b) and recirculated DEIR (RDEIR, 2024b), Soils Engineering Inc. conducted a review of naturally occurring seismic events since 1852. Their identified Region of Concern however was limited to 100 km from the Carbon TerraVault I project. Major faults within this area are illustrated in Figure 4.

From 1852 through 2020, southern California has experienced at least 20 major earthquakes with estimated Richter scale magnitudes ranging from 5.9 to 8.0. As Soils Engineering Inc. discuss, the nearest major active faults in the western portion of the CTV Project are the San Andreas Fault located approximately 23.0 to 23.3 km to the southwest, the Kern Front Fault located approximately 39.7 to 39.9 km to the northeast, the Pleito Fault located approximately 48.3 to 48.7 km to the southeast, the White Fault located approximately 48.6 to 48.9 km to the east-southeast, and the Buena Vista Fault (minor active fault) located approximately 15.42 km to the southeast. The nearest major active faults in the eastern portion of the CTV Project are the San Andreas Fault located approximately 23.9 to 24.6 km to the southwest, the Kern Front Fault located approximately 35.5 to 36.8 km to the northeast, the White Fault located approximately 39.2 to 42.5 km to the east-southeast, the Pleito Fault located approximately 40.0 to 42.9 km southeast, and the Buena Vista Fault located approximately 9.41 km to the southeast.

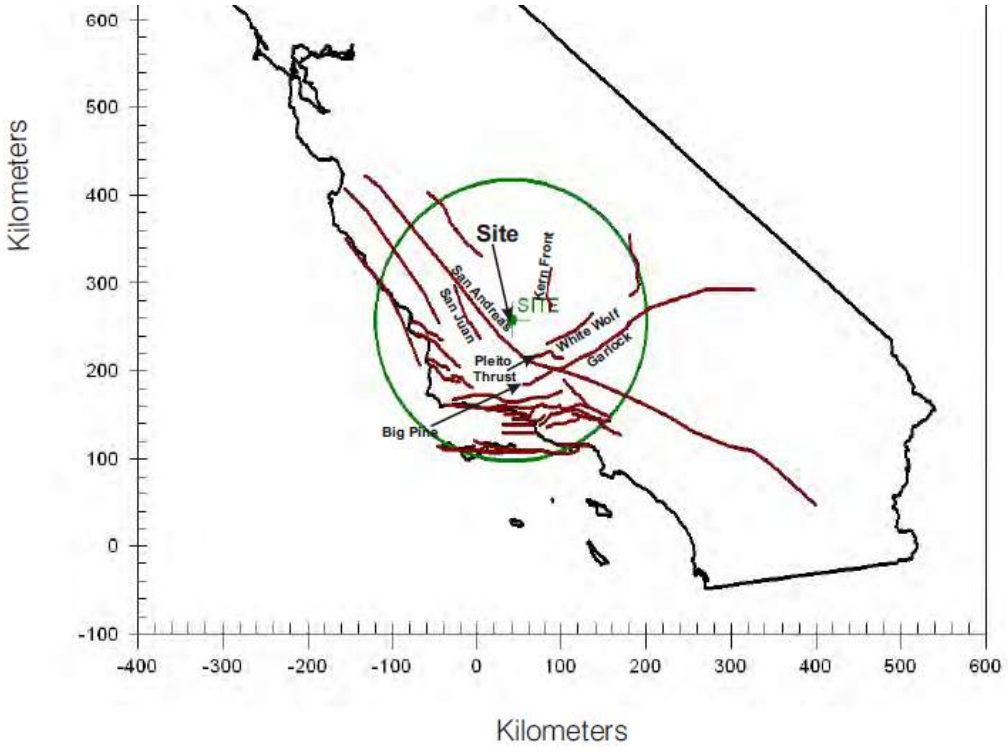


Figure 4. Identification of major faults in the vicinity of the TerraVault 1 Project. Figure from Soils Engineering, Inc. in Volume II of the recirculated DEIR (RDEIR, 2024b).

Some of these faults have produced earthquakes in excess of seismic moment magnitude **M** 7 (Figure 5). The San Andreas fault is a strike-slip fault (two blocks slide horizontally past each other). The 1857 **M** 7.9 Fort Tejon earthquake along the San Andreas fault, with an epicenter (the surface location directly

above the depth or hypocenter where rupture is initiated) in Parkfield, CA (Figure 6) was one of the greatest earthquakes ever recorded in the United States. The San Andreas fault broke the surface continuously for at least 350 km (220 miles), possibly as much as 400 km (250 miles). In Figure 6, the estimated earthquake intensity using the Modified Mercalli (MM) scale (Table 1) is estimated with distance from the epicenter. Intensity is a qualitative measure of the strength of shaking at a specific place and is characterized in terms of impact of shaking on individuals as well as on objects and structures. It is not a measure of the size of the earthquake.

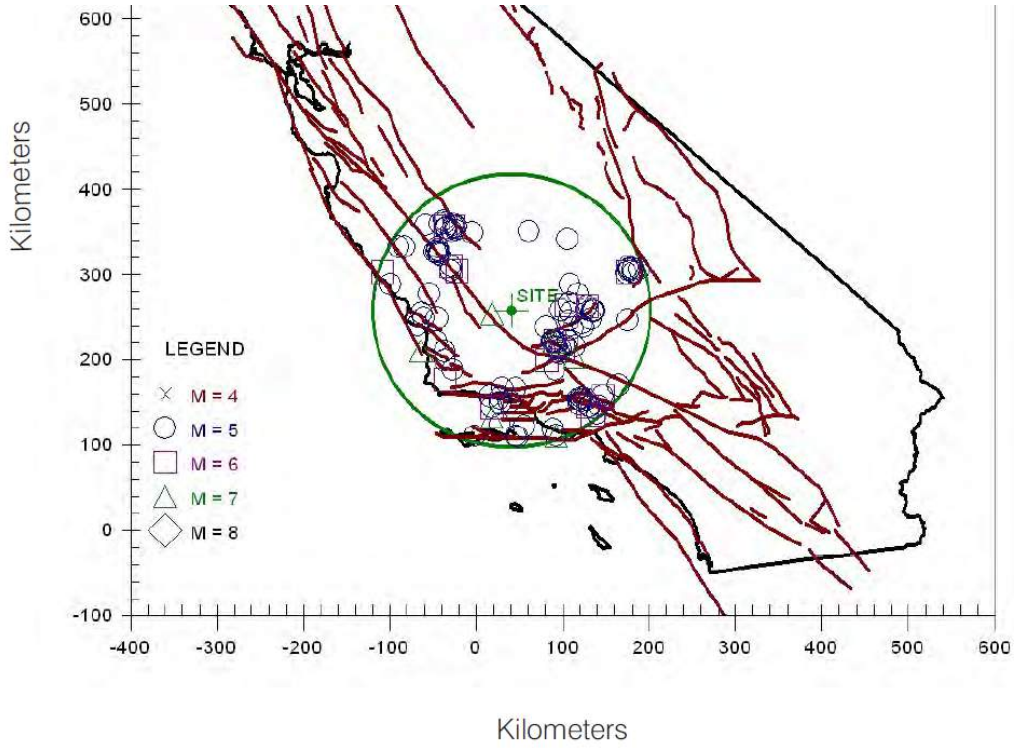


Figure 5. Magnitude of earthquakes along major faults in the vicinity of the CTV project. Figure from Soils Engineering, Inc. in Volume II of the recirculated DEIR (RDEIR, 2024b).

During the Fort Tejon earthquake, horizontal displacement as much as 9 meters was observed on the Carrizo Plain. As a result of the shaking, the current of the Kern River was turned upstream, and water ran four feet deep over its banks. The waters of Tulare Lake were thrown upon its shores, stranding fish miles from the original lake bed. The waters of the Mokelumne River were thrown upon its banks, reportedly leaving the bed dry in places. The Los Angeles River was reportedly flung out of its bed, too. Some of the artesian wells in Santa Clara Valley ceased to flow, and others increased in output. New springs were formed near Santa Barbara and San Fernando (USGS, 2023).

At the time of the earthquake, California was sparsely populated, especially in the regions of strongest shaking. Were the Fort Tejon shock to happen today, the damage would easily run into billions of dollars, and the loss of life would likely be substantial (USGS, 2023). Strong shaking was reported to have lasted for at least one minute but possibly lasted two or three minutes. The portion of the fault that ruptured in 1857 has settled into a period of dormancy and this has given rise to suggestions that future slip along that zone may be characterized by a very large 1857-type event followed by another period of inactivity (Sieh, 1978).

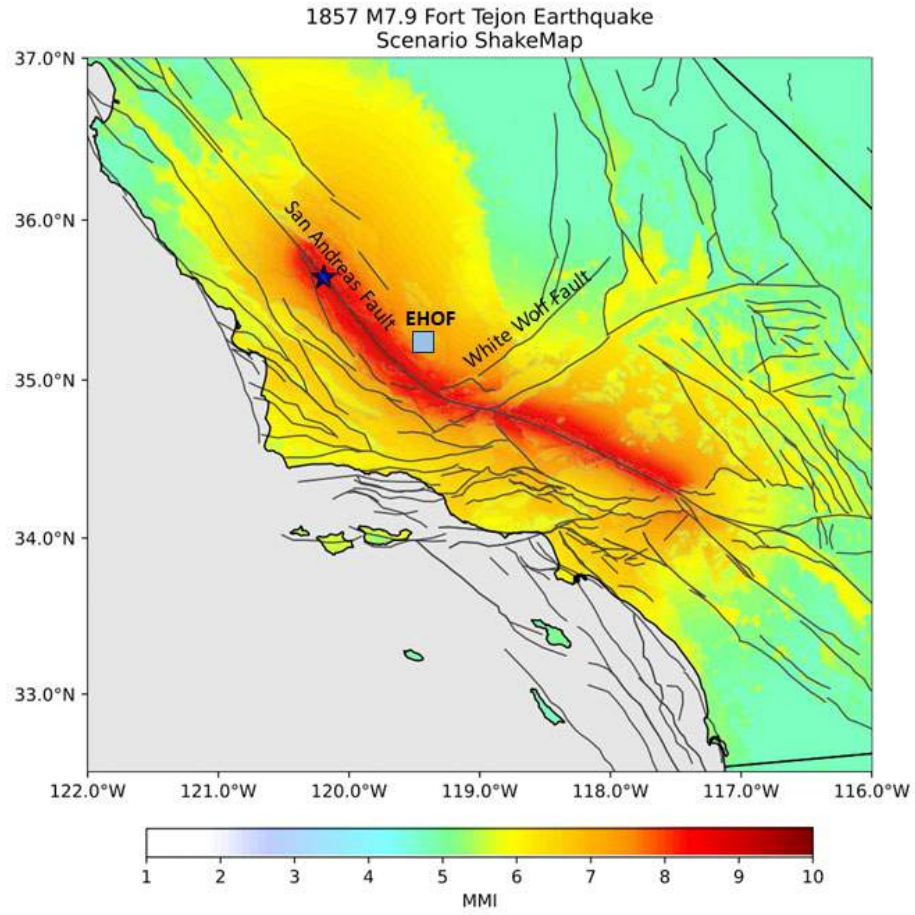


Figure 6. Location of faults in southern California and of the 1857 Tejon earthquake on the San Andreas Fault and estimated Modified Mercalli Intensity. The Epicenter illustrated by dark blue star. Approximate location of EHOF illustrated by light blue box. San Andreas and White Wolf Faults identified. Figure modified from Southern California Earthquake Data Center.

The Elkhorn Thrust, a thrust fault (reverse fault having a shallow or low angle dip) near the San Andreas fault, may have slipped simultaneously in the 1857 Fort Tejon quake indicating that future movements along the San Andreas fault zone might produce simultaneous rupture on thrust faults causing a "double earthquake" (Southern California Earthquake Center). Reverse faults (hanging wall moves up and over the foot wall) are common in southern California and other areas experiencing tectonic compression (GWPC, 2021).

As discussed by Soils Engineering, Inc. in Volume 2 of the recirculated DEIR (RDEIR, 2024b), an earthquake of **M** 8.0 has been estimated for this segment of the San Andreas Fault having a conditional probability of occurrence of 0.1 (10%) over the 30-year period of 1988 to 2018. Other segments of the San Andreas fault include the Cholame (north) and Mojave (south) segments. Their respective distances from the site and characteristic magnitudes are 58 miles and **M** 7.3 (Cholame) and 78 miles and **M** 7.8 (Mojave). The associated conditional probabilities of occurrence, for the 30-year period of 1988 to 2018 were 0.3 (30%) for both segments.

Table 1. Modified Mercalli Intensity, peak ground acceleration (PGA), and peak ground velocity (PGV) for the central United States. Source: GWPC (2021).

MMI	Description	PGA (g)	PGV (cm/sec)	Observations (Richter 1958)
I	Not felt	< 0.00007	< 0.003	Not felt except by a few under especially favorable circumstances.
II to III	Weak	0.0008	0.04	Felt by only a few people, often indoors. Hanging objects swing. May not be recognized as an earthquake.
IV	Light	0.01	0.5	Hanging objects swing. Vibration like passing of heavy trucks; or sensation of a jolt like a heavy ball striking the walls. Standing motor cars rock. Windows, dishes, doors rattle. Glasses clink. Crockery clashes. In the upper range of IV, wooden walls and frames creak.
V	Moderate	0.05	3.0	Felt outdoors; direction estimated. Sleepers awakened, liquids disturbed, some spilled. Small unstable objects displaced or upset. Doors swing, close, open. Shutters, pictures move. Pendulum clocks stop, start, change rate.
VI	Strong	0.09	6.5	Felt by all. Many frightened and run outdoors. Persons walk unsteadily. Windows, dishes, glassware broken. Knickknacks, books, etc., off shelves. Pictures off walls. Furniture moved or overturned. Weak plaster and masonry cracked. Small bells ring (church, school). Trees, bushes shaken.
VII	Very strong	0.15	14	Difficult to stand. Noticed by drivers of motor cars. Hanging objects quiver. Furniture broken. Damage to masonry D, including cracks. Weak chimneys broken at roofline. Fall of plaster, loose bricks, stones, tiles, cornices, un-braced parapets, and architectural ornaments. Some cracks in masonry. Waves on ponds; water turbid with mud. Small slides and caving in along sand or gravel banks. Large bells ring. Concrete irrigation ditches damaged.
VIII	Severe	0.27	30	Steering of motor cars affected. Damage to masonry; partial collapse. Some damage to masonry B; none to masonry A. Fall of stucco and some masonry walls. Twisting, fall of chimneys, factory stacks, monuments, towers, elevated tanks. Frame houses moved on foundations if not bolted down; loose panel walls thrown out. Decayed piling broken off. Branches broken from trees. Changes in flow or temperature of springs and wells. Cracks in wet ground and on steep slopes.

The White Wolf Fault is a high-angle reverse fault with a small component of left-lateral slip. Movement along this fault was the cause of the **M** 7.5 1952 Bakersfield Earthquake, which most consider to be the third largest historic quake in California, after the 1857 Tejon and 1906 San Francisco quakes. The White Wolf fault is traceable for only about 48 km (34 miles), much less than the fault length typically thought necessary to produce such a major earthquake. The earthquake caused severe damage as far away as Las Vegas. In addition, there were at least 20 aftershocks of **M** 5 or greater associated with the initial **M** 7.5 event (San Joaquin Valley Geology).

Ground motion can cause structural and nonstructural damage to buildings as well as to civil structures, such as dams, bridges, highways, railroads, tunnels, pipelines, tanks, and airport runways. It is commonly accepted that structural damage to modern engineered structures generally happens for earthquakes larger than **M** 5.0 (GWPC, 2021). For example, for the National Seismic Hazard Maps, which are the basis for the building codes in the U.S. (International Building Code), the U.S. Geological Survey (USGS) uses a minimum magnitude of **M** 5.0 in the western U.S. and **M** 4.75 in the central and eastern U.S. in their hazard calculations (Petersen et al. 2014). Poorly designed or constructed buildings, such as unreinforced masonry, for example, brick and adobe, and buildings built before modern building codes can be subject to nonstructural damage at magnitudes as low as **M** 4.0 and, in some rare cases, as low as **M** 3.0 (GWPC, 2021). It is unclear what magnitude seismic event would be sufficient to cause damage to wellbores.

However, as previously stated, seismic events below **M** 3 or 4 can damage wellbores. Hence, the California Carbon Capture and Sequestration Protocol requirement for a determination of integrity of any well, facility, or pipeline when an earthquake of **M** ≥ 2.7 has been detected within a radius of one mile of CO_2 injection operations is reasonable.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) for both the 26R and A1 - A2 reservoirs, CTV states that during the 1952 Kern County earthquake, there were no reservoir containment issues associated with oil and gas operations at the Elk Hills Oil Field. However, as stated in both the DEIR and recirculated DEIR, while the 26R reservoir was discovered in the 1940s, it was not developed until the 1970's. Also, the A1-A2 reservoir was not discovered until the 1970s. Hence, CTV's statement in this regard is misleading and should be removed from the recirculated DEIR.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b) for both the 26R and A1 - A2 reservoirs, CTV states that the Area of Review will be reevaluated if seismic "events reasonably associated with CO_2 injection that are greater than **M** 3.5." The document fails to properly explain the basis of this determination. In the California Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CARB, 2018), if an earthquake of **M** ≥ 2.7 is detected within a radius of one mile of CO_2 injection operations, a determination must be made whether the mechanical integrity of any well, facility, or pipeline within this radius has been compromised. The County should consider this measure in its analysis.

Comment: Seismic risk is calculated from four main contributing factors. The first factor is seismic hazard, which is the probability of exceedance of a specified ground motion intensity. The second factor is exposure, which is the infrastructure or population potentially affected by seismicity. The third factor is fragility, which is the susceptibility of each element of exposure to damage from ground motion intensity. The fourth factor is consequence, which is the metric chosen to quantify the risk (e.g., economic impact, loss of CO_2 containment) (Mitchell and Green, 2017). The seismic risk analysis conducted in the recirculated DEIR is deficient because it fails to consider all four factors, especially for legacy wells which were not considered at all. In the document, hazard curves were generated, however, legacy wells were not identified as part of exposure to seismicity. Fragility functions were not identified for any infrastructure including legacy wells and the consequences of leakage through legacy wells were not quantified. Hence, a comprehensive seismic risk analysis was not conducted in the recirculated DEIR.

Hazard Evaluation of Natural Seismic Events

Hazard curves can be generated to evaluate a given percent probability of exceedance of a peak ground acceleration or spectral acceleration level over a period of time (e.g., 10% probability of exceedance in 50 years). Peak ground acceleration is a measure of the maximum force experienced by a small mass located at the surface of the ground during an earthquake. It is an index to hazard for short stiff structures. Spectral acceleration is a measure of the maximum force experienced by a mass on top of a rod having a particular natural vibration period. Short buildings (e.g., less than 7 stories) have short natural periods (e.g., 0.2-0.6 sec). Tall buildings have long natural periods (e.g., 0.7 sec or longer) (USGS). Peak ground acceleration appears to be the appropriate metric to evaluate potential to wellbores.

Templeton et al. (2021) state that a site-specific probabilistic seismic hazard analysis should be conducted in accordance with current practice of earthquake hazard estimation to evaluate the baseline hazard from

natural tectonic seismicity. Input into the site-specific probabilistic seismic hazard analysis should include the following:

- A database of potentially damaging earthquake sources that may impact the ROC, that experienced activity during the Quaternary Period (past 1.6 million years), including fault-specific sources and areal sources where appropriate. Areal seismic sources are distinct volumes within the Earth's crust that encompass concentrated zones of seismicity,
- Spatial, temporal, and frequency-magnitude distribution models for each seismic source.
- Region appropriate ground motion models for tectonic earthquakes as a function of at least earthquake magnitude and travel path. A ground motion model relates a ground motion parameter such as peak ground acceleration or peak ground velocity to magnitude, distance, and site condition. There are numerous models for tectonically active regions, such as the western U.S. (GWPC, 2021). The models for the western U.S. rely on empirical motion data obtained from instrumental records of earthquakes or numerical modeling in the absence of adequate strong motion data. Empirical models are often developed by performing a statistical regression on a ground motion parameter from the recorded data to find the best fitting model. Current ground motion models do not extend below **M** 3.0 (GWPC, 2021). Common inputs into a ground motion model include magnitude, distance, and site condition. For small earthquakes generally less than **M** 4, hypocentral distance is an adequate distance metric. For larger events, a distance metric that accounts for the finite dimensions of the fault rupture area is desirable. For most models, rupture distance (the shortest distance to the fault plane) is used (GWPC, 2021). Site condition inputs also are required to accurately predict ground shaking, particularly at a soil site (GWPC, 2021).
- Information from geological, geophysical, and topographical studies within the ROC should be included to incorporate local site responses.

Templeton et al. (2021) state a seismic hazard report should be prepared by a licensed professional having demonstrated competence in the field of seismic hazard assessment. The seismic hazard report should contain site-specific assessments of the seismic hazard affecting the project and relevant sites within the ROC. The report should identify any known seismic hazards that could adversely affect relevant sites within the ROC in the event of an earthquake. Results from the probabilistic seismic hazard analysis should include multiple hazard curves and hazard maps to report the results from the baseline seismic hazard analysis due to natural seismicity before injection operations commence. Federal and state permitting agencies should then independently review the seismic hazard report to determine the adequacy of the hazard evaluation. The reviews should be conducted by licensed professionals having demonstrated competence in the field of seismic hazard assessment.

Volume II of the recirculated DEIR (RDEIR, 2024b) contains a report entitled "Preliminary Soil and Geologic Evaluation Terra Vault 1 Carbon Capture Project Elk Hills" completed by Soil Engineering Inc. that contains a probabilistic seismic hazard analysis for the facility. Soils Engineering Inc. used the computer modeling program EQSEARCHWIN version 3.0 (Thomas Blake) to evaluate historical earthquakes in the area of the site over the last 200 years. The largest estimated site accelerations are 0.221g (Section 36) to 0.295g (Section 7/18) from a 7.9 magnitude earthquake on January 9, 1857.

A number of active faults are located within a 50-mile radius of the subject site. Soils Engineering Inc. used the computer modeling program EQFaultwin vers. 3.0 (Thomas Blake) to evaluate the effect that a major earthquake within a 50-mile radius might have on the site. The program computed the maximum

peak site ground accelerations resulting from an earthquake. Results of this analysis are presented in Table 2.

Table 2. Identification of faults near the site and associated maximum earthquake magnitude, estimated maximum peak ground acceleration at the site, and associated site intensity. Table from Soils Engineering, Inc. in Volume II of the recirculated DEIR (RDEIR, 2024b).

FAULT	Approximate Distance (Km)	Maximum Earthquake Magnitude (Mw)	Maximum Peak Ground Acceleration	Estimated Site Intensity (MM)
San Andreas (Other Segments)	**23 to 24.6**	7.4 to **8.0**	0.128 to **0.258**	VIII to **IX**
Kern Front	35.5 to 39.9	6.3	0.085 to 0.093	VII
White Wolf	39.2 to 48.9	7.3	0.123 to 0.146	VIII
Pleito Thrust	40.0 to 48.7	7.0	0.105 to 0.122	VII
San Juan	42.6 to 47.6	7.1	0.093 to 0.101	VII
San Luis Range	72.8 to 76.2	7.2	0.083 to 0.086	VII
Big Pine	64.9 to 73.4	6.9	0.060 to 0.066	VI
Great Valley 14	79.6 to 85.7	6.4	0.050 to 0.052	VI
Garlock (west)	70.3 to 73.6	7.3	0.069 to 0.076	VI to VII

This analysis estimates that a maximum peak ground acceleration of up to 0.258g would be felt at the site as a result of a maximum earthquake of **M** 8.0 on the San Andreas Fault approximately 23 to 24.6 kilometers away (Table 2). A maximum probable earthquake of **M** 7.3 on the White Wolf Fault approximately 39.2 to 39.9 kilometers away would create a peak site ground acceleration of up to 0.146g at the site.

Soils Engineering Inc. then utilized USGS's Unified Hazard Tool (USGS, 2024) to generate hazard curves for the site which was re-produced for this report in Figure 7. The USGS program calculates peak ground and spectral acceleration at a site for all the earthquake locations and magnitudes believed possible in the vicinity of the site. Each of these magnitude-location pairs is believed to happen at some average probability per year. Small ground motions are relatively likely, large ground motions are very unlikely. Beginning with the largest ground motions and proceeding to smaller, probabilities are summed to calculate a total probability for a particular period of time (USGS).

For the project location, a peak ground acceleration rate of 0.4363g was estimated having a 5% probability of exceedance in 50 years with an annual rate of exceedance = 1.025E-03 or a return period of 475 years (RDEIR, 2024b). The return period or time horizon is the inverse of the annual rate of exceedance. Using the USGS "rule of thumb" for calculating return period, this is approximately equivalent to a 9.8% probability of exceedance in 100 years, a 42% probability of exceedance in 500 years, and a 69% probability of exceedance in 900 years. A further examination of the hazard curves

(Figure 8) (not included in the recirculated DEIR) indicates a peak ground acceleration of 0.3175g having a 10% probability of exceedance in 50 years, 19% probability in 100 years and a 64% probability of exceedance in 400 years. Care was taken in these calculations to ensure that r* ≤ 1 where r* = r(1+0.5r) and r = probability as recommended by USGS (USGS, 2024).

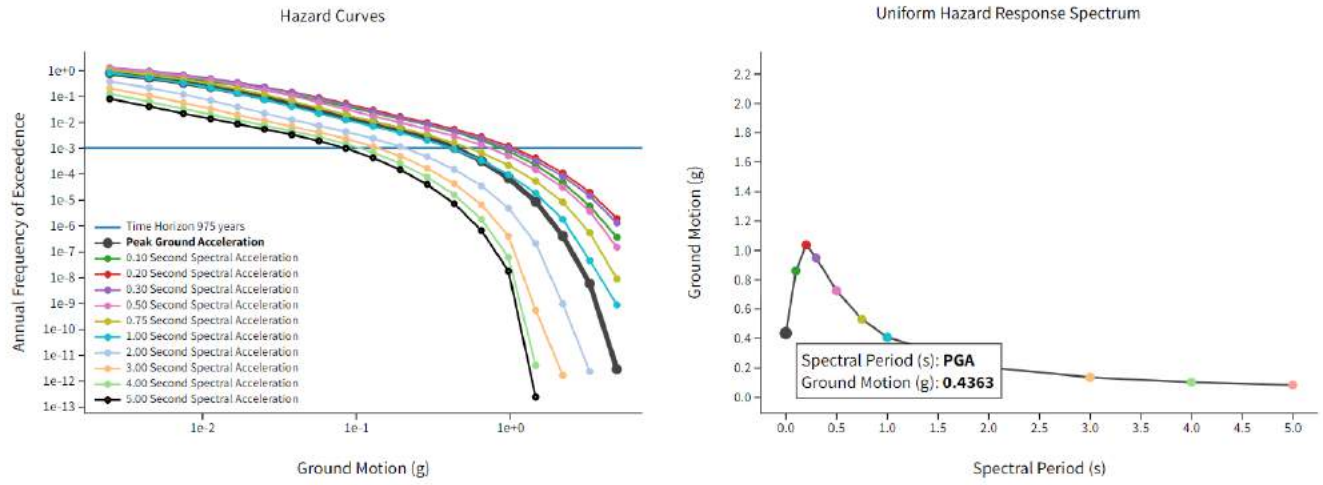


Figure 7. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 5% in 50 years. For an annual frequency of exceedance of 1.025E-03 or return period (inverse of frequency of exceedance) of 975 years, peak ground acceleration = 0.4363g (43.63% of the gravitational constant).

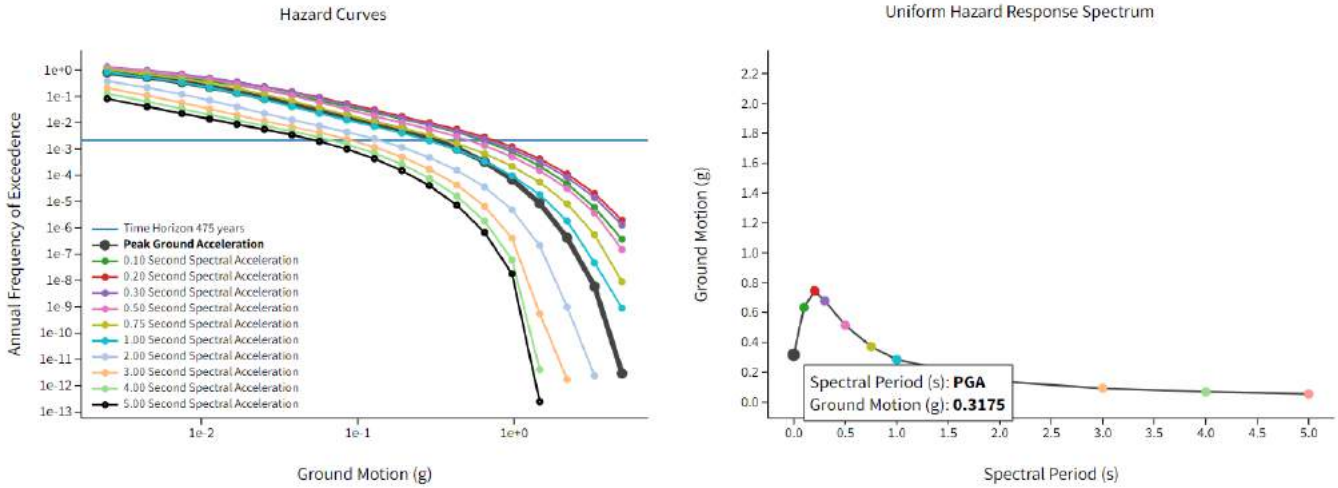


Figure 8. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 10% in 50 years. For an annual frequency of exceedance of 2.105E-03 or return period (inverse of frequency of exceedance) of 475 years, peak ground acceleration = 0.3175g (31.75% of the gravitational constant).

Comment: In Volume 1 of the recirculated DEIR (RDEIR, 2024a), in Impact 4.7-1, it is stated that an earthquake may, *"Directly or Indirectly Cause Substantial Adverse Effects, Including the Risk of Loss,*

Injury, or Death Involving the Rupture of a Known Earthquake Fault, as delineated on the most recent Alquist-Priolo earthquake fault zoning map issued by the state geologist for the area based on other substantial evidence of a known fault." This impact is considered potentially significant. Mitigation measure 4.7-1 consists of preparing *"a comprehensive seismic activity monitoring plan that includes, but is not limited to, connection to the Statewide seismic monitoring program of California Seismic Network (CISN)… The final plan shall be approved by the California Air Resources Board and include all requirements of State law including but not limited to: Appropriate subsurface monitoring to ensure geologic sequestration of injected carbon dioxide; Identification of hazards and conditions that may require the suspension of carbon dioxide injections; notification protocols for all applicable agencies and emergency procedures. All requirements for seismic monitoring adopted by the California Air Resources Board – "Carbon Capture, Removal, Utilization and Storage Program" shall be implemented."*

While a seismic monitoring plan would be able to detect an earthquake, a seismic monitoring program would not reduce damage to surface and subsurface facilities (e.g., wellbores). Unlike induced seismicity as a result of injection of CO_2, monitoring of natural seismicity is not mitigation. Cement used outside of well casing is a brittle material susceptible to damage from ground motion. Hence, a seismic monitoring program would not mitigate damage from a natural major earthquake within 100 km of the Carbon TerraVault I project to a less-than-significant level. In the presence of moderate seismic activity at the project area (e.g., MMI ≥ 5, PGA ≥ 0.05g, PGV ≥ 3.0 cm/s), mitigation should include assessment of leakage at wellbores and reentry and replugging of wellbores in the event of increased leakage from wellbores. The Level of Significance for Impact 4.7-1 should be changed from Less than Significant to Significant and Unavoidable.

Comment: In Volume II of the recirculated DEIR (RDEIR, 2024b), Soils Engineering Inc. states, that *"Project proponent will design structures in accordance with state and county code requirements for seismic ground shaking and geotechnical and geohazard constraints. Designs shall comply with seismic, soil response at the site, and structural dynamic characteristics contained in the Kern County Code of Building Regulations and the California Building Code and State of California design standards Chapter 16 and 18. These design standards are required by law for all new structures in Kern County and were established to reduce the potential impact to structures from strong seismic shaking to a less than significant level."*

These regulations do not address wellbore integrity. It is not clear whether wellbores can withstand a peak ground acceleration of 0.258g, let alone peak ground accelerations of 0.3175g or 0.4363g. A peak ground acceleration of 0.27 g is associated with a Modified Mercalli Intensity of VIII with observations including: steering of motor cars affected; damage to masonry and some masonry walls; twisting, fall of chimneys, factory stacks, monuments, towers, elevated tanks; frame houses moved on foundations if not bolted down; loose panel walls thrown out; changes in flow or temperature of springs and wells; and cracks in wet ground and on steep slopes. Hence, this mitigation measure is not appropriate, at least for wellbores like those that would be impacted at Elk Hills. Also, Templeton et al. (2021) state that an evaluation of the anticipated losses as a function of ground motion intensity can be achieved either directly by using vulnerability functions or indirectly through the use of fragility functions. Vulnerability functions directly relate ground motion intensity to anticipated losses. Fragility functions relate ground motion intensity to the probability of damage and are often expressed as either loss ratio curves, damage probability matrices, or fragility curves (Templeton et al., 2021). There does not appear to be vulnerability and fragility functions associated with oil and gas wellbores. However, based on a Modified Mercalli

Intensity of at least VIII, wellbore damage would reasonably be expected from a major seismic event within 100 km of the Carbon TerraVault I project. The Level of Significance for Impact 4.7-2 should be changed from Less than Significant to Significant and Unavoidable. In the presence of moderate seismic activity at the project area (e.g., MMI ≥ 5, PGA ≥ 0.05g, PGV ≥ 3.0 cm/s), mitigation should include assessment of leakage at wellbores and reentry and replugging of wellbores in the event of increased leakage from wellbores.

Comment: CARB requires that an operator use appropriate tools to characterize potential risks of adverse impacts on the environment, health, or safety, by combining the assessment of the probability of occurrence and the magnitude of the adverse impacts of identified project risk scenarios. Risk scenarios identified as part of this assessment must be classified high risk, medium risk, or low risk, according to the combination of probability of occurrence during a 100-year period and the severity of potential consequences (Table 3). Given an approximately 10% and 20% probability of a major seismic event inducing a peak ground acceleration of 0.44 g and 0.32 g, respectively, at the TerraVault I Project area, risk should be classified as high. At a minimum, this high-risk classification should mandate robust evaluation and monitoring of wellbore integrity.

Table 3. CARB Risk scenario classification.

	Insubstantial[2]	Substantial[2]	Catastrophic[2]
> 5%[1]	Medium risk	High risk	High risk
1-5%[1]	Low risk	Medium risk	High risk
< 1%[1]	Low risk	Medium risk	Medium risk

1 Probability of occurrence over 100 years
2 Severity of potential consequences

Additional Hazard from Induced Seismicity

Induced seismicity is of concern for faults that are optimally oriented, critically stressed, and of sufficient size to cause damage sufficient to induce leakage of sequestered CO_2. Leakage of CO_2 could occur through a damaged confining layer, from activation of faults penetrating a confining layer, or through wellbore damage.

Induced seismicity considerations in the Class VI regulations are largely limited to CO_2 migration through faults penetrating the confining layer. EPA (2013) states that use of seismic hazard maps to demonstrate the reasonable expectation that no induced seismic events would occur during the course of a CCS project may fulfill the requirements at 40 CFR 146.82(a)(3)(v). However, if such maps indicate a substantial likelihood of seismic activity, other required geologic information, such as geomechanical data, depth to confining zones, and fault stability analysis may be needed to demonstrate that seismic activity will not compromise subsurface containment (EPA, 2013). An owner/operator is required to determine the

"location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the Area of Review, along with a determination that they will not interfere with containment" (40 CFR 146.82(a)(3)(ii)). The owner/operator is also required to demonstrate the presence of a "confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced fluids" (40 CFR 146.83(a)(2)).

It is stated in the Class VI permit applications that in 2019 three-dimensional (3D) seismic survey data was re-processed to allow a more focused structural image around tight folds and faults (EPA, 2024). Offsetting the 31S anticline are high-angle reverse faults that are oriented NW-SE. It is stated that these inactive faults penetrate the lowest portions of the Monterey Formation but not the lower Reef Ridge Shale above the Monterey Formation in the 26R reservoir. It is also stated the 26R reservoir is continuous across the Area of Review and the sands pinch-out up-dip and on the channel edges. As such, the 26R reservoir has minimal connection outside the Area of Review creating a reservoir with no connection to regional saline aquifers (EPA, 2024). The emphasis of EPA regulations are on upward migration of brine and CO_2 as opposed to downward propagation of pressure. The concern with faults in the Monterey Formation may be uncertainty associated with potential propagation of pressure below the storage formation, such as has occurred during disposal of produced water in Class II disposal wells and during hydraulic fracturing.

Increased subsurface fluid injection activity has led to increased seismicity at some sites, including near oil and gas wastewater (produced water) disposal sites, hydraulic fracturing sites, and engineered geothermal systems (Ellsworth, 2013; Keranen and Weingarten, 2018; Templeton et al., 2020). Induced seismicity has raised concerns about the scalability of geologic storage of CO_2 considering the seismic hazard and risk associated with far-reaching subsurface pressurization and adjacent basement rocks (Zoback and Gorelick, 2012; White and Foxall, 2016). Even in areas of low to moderate natural seismic activity, fluid injection may induce earthquakes in excess of **M** 4 (Templeton et al., 2023).

Seismogenic response to fluid injection may vary strongly from site to site and between different injection intervals (Templeton et al., 2023). Weingarten et al. (2015) and Schultz et al. (2018) show that the potential for inducing earthquakes in wastewater disposal and hydraulic fracturing, respectively, correlates positively with the total injected fluid volume and the rate of injection. However, the causative mechanisms of induced seismicity and geomechanical conditions at injection sites are diverse and involve many poorly constrained or unknown parameters. Significant uncertainties on the likelihood of inducing seismicity can persist even after careful characterization. It is not fully understood why some operations can cause significant induced seismicity while others do not (Templeton et al., 2021).

Before 2011, the **M** 4.8 event in 1967 near Denver, Colorado, was the largest event widely accepted in the scientific community as having been induced by fluid injection. The Rocky Mountain Arsenal earthquakes demonstrated how the diffusion of pore pressure within an ancient fault system can initiate earthquakes many kilometers from the injection point, delayed by months or even years after injection ceased (Hermann et al. 1981). The **M** 5.7 event in November 2011 in central Oklahoma is now the largest known induced seismic event (Kerenan et al., 2013). This earthquake damaged homes and unreinforced masonry buildings in the epicentral area and was felt as far as 1000 km away in Chicago, Illinois.

Seismicity may be induced tens of kilometers away from large-scale injection. The occurrence of seismicity farther away from injection implies that stress changes much smaller than 1 MPa may be

sufficient to trigger seismicity even in naturally quiescent areas. Recent studies indicate that effective stress changes on the order of 100 kPa (14.5 psig) or less can found near earthquake hypocenters (Keranen et al., 2014; Barbour et al., 2017; Norbeck and Rubinstein, 2018; Zhai et al., 2020).

Even faults capable of **M** 5 earthquakes may be previously unknown. In many of the induced seismicity cases, faults that hosted even the largest events > **M** 5 were not known beforehand (Templeton et al., 2023). Even natural events, such as the 2014 Napa, California earthquake, often occur on blind faults (Brocher et al., 2015). This can be related to the difficulty of imaging faults in basement rocks or the lack of vertical offset in the sedimentary overburden from subvertical strike-slip faults.

The largest injection-induced events have all involved faulting that is considerably deeper than the injection interval (Horton, 2012), suggesting that transmission of increased pressure into the basement elevates the potential for inducing earthquakes. Hence, during geologic storage of CO_2, it is important that pressure perturbation from injection not be transmitted below depths of injection.

Few commercial scale geologic CO_2 storage sites exist that can be used as prototypes to study induced seismic response. The Cogdell CO_2 enhanced oil recovery project has been associated with felt earthquakes. The seismicity in the Cogdell project has been attributed to the very high injection rates and the presence of faults in the reservoir (Gan and Frohlich 2013). At the Illinois basin–Decatur project and the associated Illinois Industrial Carbon Capture and Sequestration Sources project, as of 2022, 2.8 million metric tons of CO_2 have been injected into the Mt. Simon saline sandstone reservoir with detection of nearly 20,000 seismic events with **M** up to 1.2, although none have been felt at the surface (Williams-Stroud et al., 2020). As a result of seismic activity, injection was moved to a shallower zone within the Mt. Simon sandstone resulting in fewer seismic events (Williams-Stroud et al., 2020).

Dvory and Zoback (2021) state that since depleted oil and gas fields have decreased pore pressure compared to initial conditions, it is plausible that the risk of induced seismicity in depleted oil and gas fields may be less than that associated with other storage configurations (e.g., saline aquifers) because increased pore pressure beyond initial conditions is one of the main causes of injection-induced seismic events.

One study of particular relevance to the Carbon TerraVault I project is a potentially injection-induced earthquake swarm in 2005 associated with the WhiteWolf Fault (Goebel et al., 2016). It was comprised of a **M** 4.5 event on 22 September, followed by two **M** 4.7 and **M** 4.3 events the same day. The White Wolf swarm is suspected to be connected to fluid-injection activity at the Tejon Oil Field based on a statistical assessment of injection and seismicity rate changes (Goebel et al., 2015). Injection wells at the Tejon Oil Field targeted a 25–30 m thin, highly permeable stratigraphic zone within the Monterey formation composed of turbiditic sand lenses with maximum lateral extents of 1 to 2 km (Goebel et al., 2016). Recall that turbiditic sand lenses are targeted for CO_2 storage at the Carbon TerraVault I project.

Based on geological mapping, seismicity, and well-log data, Goebel et al. (2016) identified a seismically active normal fault referred to as “Tejon Fault” in proximity to the Tejon Oil Field which deepened (7.7 km) toward the northwest below the Wheeler Ridge fault before intersecting with the White Wolf Fault 8 km from injection wells (Figure 9). Pressure diffusion was likely influenced by an 11 km high permeability pathway along the seismically active part of the Tejon fault (Goebel et al., 2016). Numerical modeling indicated that for a fault zone permeability above ~300 mD and fault width below ~800 m, a pressure increase of just 0.01 MPa (1.5 psi) was sufficient to induce seismicity on a fault favorably

oriented to slip (Goebel et al., 2016) as also observed by Keranen et al. (2014) and Hornbach et al. (2015). Given the discussion here, the primary concern at the Carbon TerraVault I project is pressure transmission below the Monterey Formation, not above it. Investigative studies have demonstrated that pressure propagation can occur over large distances and depths during injection of fluids and that a very small pressure differential can induce seismicity. Hence, analysis conducted by CTV in the recirculated DEIR and Class VI permit applications does not eliminate the potential for inducted seismicity at the Carbon TerraVault I project.

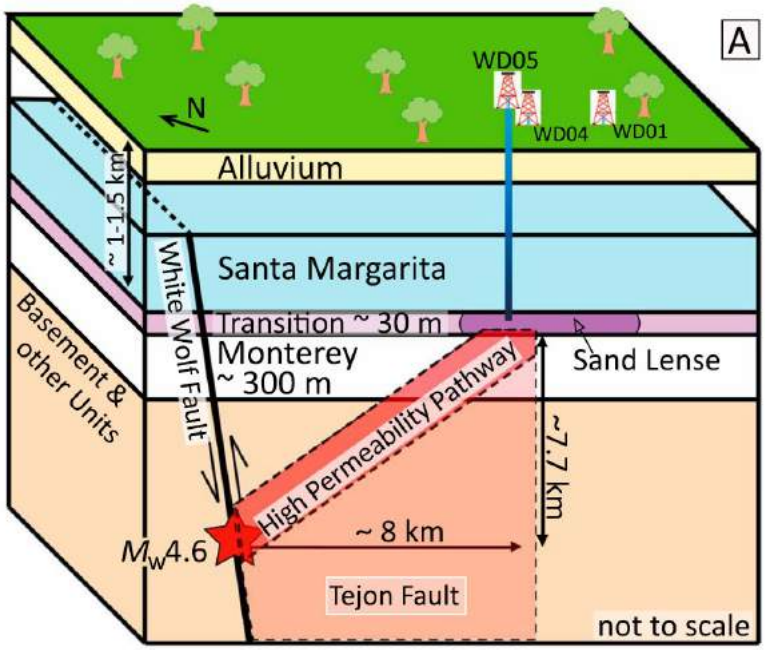


Figure 9. Schematic representation of pressure migration along a high-permeability fault between the Tejon Oil Field and a M 4.6 seismic event along the White Wolf Fault.

Comment: For induced seismicity, the primary concern here is pressure transmission below the Monterey Formation, not above it. In the Class VI regulations, the primary concern is leakage through faults in the confining layer, not transmission of pressure and induced seismicity below the storage formation. Hence, neither EPA regulations nor the recirculated DEIR adequately consider induced seismicity. Callas et al. (2022) state that lack of a lower confining seal (permeability > 100 nanodarcy) is a disqualifying threshold for geologic storage of CO_2 because of potential pressure propagation to basement rock capable of producing seismic activity. According to schematics provided in Volume II of the recirculated DEIR (RDEIR, 2024b), the Reef Ridge Shale bounds both the upper lower Monterey Formation and has an average permeability of 0.01 millidarcy or 10,000 nanodarcy. As discussed, in the 26R and A1 - A2 Storage Areas, CTV states that final pressure will target the initial reservoir pressure at the time of discovery. Hence, this would decrease but not eliminate the possibility of induced seismicity.

Seismic Monitoring Network Design

The Class VI regulations do not include an explicit requirement for a seismic monitoring plan. However, in its Class VI Implementation manual for UIC Program Directors, EPA states that concerns about

seismicity or uncertainties about the seismic history of the site raised during site characterization may necessitate the inclusion of passive seismic monitoring (EPA, 2013).

Seismic data needs to be gathered, analyzed, and archived during the lifetime of a project for geologic storage of CO_2. These data are needed to accurately assess and periodically reassess the natural and induced seismic hazard and risk associated with the project and to aid in the rapid and effective detection and characterization of the seismicity at the site. This data is especially needed as input into induced seismicity mitigation plan protocols (e.g., traffic light systems). In general, the National Earthquake Information Center (NEIC) and other national or state monitoring systems are not sufficient for monitoring induced seismicity at a facility for geologic storage of CO_2 (Templeton et al., 2021). Routine detection of small events in the immediate vicinity of the injection site is necessary to detect problematic developments as early as possible.

The California Carbon Capture and Storage Review Panel recommended that seismic risks be considered during the operation and monitoring of CO_2 storage projects and stated that specialized seismic monitoring may be warranted (California Institute for Energy and Environment, 2010). The CARB protocol for CO_2 sequestration requires that the operator deploy and maintain a permanent, downhole seismic monitoring system to determine the presence or absence of any induced micro-seismic activity associated with all wells and near any discontinuities, faults, or fractures in the subsurface (CARB, 2018). Templeton et al. (2023) state that to record seismicity within the ROC, it is expected that the footprint of the seismic network would need to extend beyond the ROC. In the 26R Reservoir and A1 - A2 Area of Review areas, CTV will monitor seismicity with a network of surface and shallow borehole seismometers. Specifically, CTV will deploy 6 sensor locations (borehole and near surface) most of which are outside the Area of Review. CTV states that this data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

The Technical Advisory Committee to the California Carbon Capture and Storage Review Panel recommended that monitoring for induced seismicity should begin during the site selection and assessment phase to establish a baseline record of the natural background seismicity in the region encompassed by the project using the state's existing seismometer network augmented by a local network. Templeton et al. (2023) recommend that prior to commencing injection operations, a seismic monitoring network should be operated for at least 6 months but preferably 1 year or longer and be designed to detect and characterize seismicity occurring in the ROC down to at least **M** 1. CTV states in the Class VI permit application that a seismic monitoring network will establish an understanding of baseline seismic activity within the area of the project and that historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline.

Comment: Templeton et al. (2023) state that a local seismic monitoring network should include a combination of high-gain sensors, which can optimally record weak ground motions from small local earthquakes, and low-gain accelerometers, which can optimally record strong ground motions from nearby larger earthquakes. Templeton et al. (2023) also state that each seismic station should measure ground motion in three orthogonal directions (e.g., up-down, north-south, and east-west) to fully capture the movement of the seismic waves as they travel through the earth. In Volume II of the recirculated

DEIR (RDEIR, 2024b), CTV states that high-sensitivity 3-component geophones will be utilized for seismic monitoring. The system will be designed with the capability of detecting and locating events > 0.0 **M** within the project area. Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The California Geological Survey should ensure that the seismic monitoring network is of sufficient robustness.

Comment: Templeton et al. (2023) state that the seismic monitoring network should be able to record and locate seismicity in the ROC with at least a 2-sigma location accuracy of 0.5 km in the horizontal direction and 1.0 km in the vertical direction. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV states that the seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft. vertical resolution at the injection depths and above. The California Geological Survey should ensure that the seismic monitoring network is of sufficient resolution.

Comment: Templeton et al. (2023) state that seismic monitoring networks should be designed, and stations located, such that ground velocities of 600 nm/s can be recorded with a signal-to-noise ratio of at least 6 in the frequency range 5–40 Hz within the ROC. In Volume II of the recirculated DEIR (RDEIR, 2024b), CTV also states that borehole sensors have been deployed to ensure a good quality signal to minimize noise and that a velocity model will be derived from vertical seismic profiles, sonic well logs, and check shots. Information on the signal-to-noise ratio in the seismic network should be provided in the recirculated DEIR.

Comment: Templeton et al. (2023) state that the data should be recorded using at least a 24-bit digital data acquisition system and a global positioning system-based field timing system to achieve the required timing accuracy of at least 1 ms. In Volume II of the recirculated DEIR (DEIR, 2024b), CTV states that waveform data is to be transmitted near real-time via cellular modem or other wireless means and archived in a database. Timing accuracy was not specified in the recirculated DEIR, but should be.

Seismicity Mitigation Plan

If the project operator obtains evidence that an earthquake has caused a failure of the mechanical integrity of wells, facilities, or pipelines, which may cause potential CO_2 emissions to the atmosphere, the project operator must implement an Emergency Remedial Response Plan (CARB, 2018). The operator should create a site-specific induced seismicity mitigation plan for the DEIR based on a Traffic Light System (TLS) framework (Templeton et al., 2023). Templeton et al. (2023) state that the TLS framework should include at least three response levels, indicating operation as usual (green), heightened awareness and reassessing and modifying as appropriate of injection operations (yellow), and stopping injection (red). In the Class VI permit application, CTV created a five-response level (green, yellow, orange, magenta, red) seismicity mitigation plan.

Comment: The preliminary results of the seismic evaluation must be reported to CARB within 30 days following the earthquake, with a final report submitted within 120 days (CARB, 2018). The report must include, at a minimum: (1) the date, time, and magnitude of the earthquake; (2) the location and distance of the epicenter from the CCS project; (3) the results of the investigation into the link between the

injection activity and the earthquake or pattern of seismicity; (4) any emergency and remedial actions taken; (5) a description of any investigations and tests conducted to assess the mechanical integrity of wells and other surface equipment, and a demonstration that the well and equipment were either not damaged by the earthquake or that mechanical integrity was restored prior to the re-initiation of injection; and (6) any identified changes necessary to the CCS project Testing and Monitoring Plan (CARB, 2018). There is no mention of reporting of seismic events to CARB in the seismicity mitigation plan in Volume II of the recirculated DEIR

Comment: Of perhaps greater concern are naturally occurring seismic events at distance from the facility. In these cases, a seismic mitigation plan specified in terms of peak ground velocity or ground acceleration would be more useful in the DEIR.

Conclusions and Recommendations

There is interest in using depleted oil and gas reservoirs, such as the Carbon TerraVault I project for geological storage of CO_2 due to extensive preexisting geological characterization and infrastructure. Also, since depleted oil and gas fields have decreased pore pressure compared to initial conditions, it is plausible that the risk of induced seismicity in depleted oil and gas fields may be less than that associated with other storage configurations (e.g., saline aquifers) because increased pore pressure beyond initial conditions is one of the main causes of injection-induced seismic events.

However, well penetrations are widely recognized as a primary pathway for leakage during geologic storage of CO_2. There are an extraordinarily large number of wellbores (354) penetrating the primary confining layer (Reef Ridge Shale) at the Carbon TerraVault I project. Leakage through wellbores will be facilitated by the high pressure of storage (~4,000 psi) and storage occurring primarily as a separate phase supercritical fluid. All 354 wellbores will eventually be in direct contact with highly pressurized supercritical CO_2 – a highly corrosive medium.

Complicating matters further is the fact that that the Carbon TerraVault I project is located in an area of high natural seismicity. The probability of a natural seismic event capable of causing wellbore damage in the project area is quite high (~20% within 100 years). Given the large number of well penetrations, high pressure during storage, storage primarily as a supercritical fluid, and natural seismicity, leakage through well penetrations is a major concern. The success or failure of geologic storage of CO_2 at the Carbon TerraVault I project will largely depend on minimizing leakage from well penetrations.

The importance of properly evaluating wellbores prior to plugging to determine the need for corrective action and evaluating wellbores that have been plugged sometime in the past cannot be stressed enough. Unfortunately, tables provided for the 26R and A1- A2 reservoirs in Volume II of the recirculated DEIR do not provide sufficient information on wellbore integrity. CTV claims that no wellbores require corrective action – a claim that must be viewed with considerable skepticism since wellbore integrity failure rates published from oil and gas sites in the literature range from 2 to 75%.

In one column of the tables provided in the recirculated DEIR, annular isolation of wellbores within the upper confining later is subjectively described as "*adequate*." No proof of adequacy of any wellbore beyond those used for injection was provided in the DEIR or Class VI permit applications. CTV should immediately submit all supporting information (drilling logs, well completion and plugging reports,

casing and cementing records, records on internal and external mechanical integrity testing, cement bond/variable density logs, and wellbore diagrams) to the public record.

In the absence of a robust investigation of wellbore integrity at the Carbon TerraVault I project, the recirculated DEIR should not be approved.

Funding

Funding for this report was supplied by the Center for Applied Environmental Science at the Environmental Integrity Project.

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Attachment A
to Technical Comments of Dominic DiGiulio, PhD:
Qualifications and Experience

Dominic DiGiulio

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Background

I am a retired geoscientist from the U.S. Environmental Protection Agency. I have conducted research on: emissions of volatile organic compounds from abandoned wells, leakage of produced water, condensate, and drilling fluids from impoundments to groundwater, contamination of groundwater from hydraulic fracturing, subsurface methane and carbon dioxide migration (stray gas), intrusion of subsurface vapors into indoor air (vapor intrusion), gas flow-based subsurface remediation (soil vacuum extraction, bioventing), groundwater sampling methodology, soil-gas sampling methodology, gas permeability testing, and solute transport of contaminants in soil. I assisted in the development of EPA's original guidance on vapor intrusion and the EPA's Class VI Rule on geologic sequestration of carbon dioxide. I have served as an expert witness in litigation relevant to oil and gas development, testified before State oil and gas commissions on proposed regulation, and testified before Congress on the impact of oil and gas development on water resources. My consulting services have included reports on: stray methane gas migration, geological carbon storage in Louisiana, storage of natural gas liquids in solution mined caverns, proposed oil and gas regulations in Colorado, impact to groundwater resources from Class II disposal wells in Ohio, Idaho, and Florida, produced water transport in barges along the Ohio River, proposed EPA regulation on discharge of produced water to surface water, and Bureau of Land Management leases in Wyoming, Montana, and Colorado.

Education

B.S., Environmental Engineering, Temple University, Philadelphia, PA (1982)
M.S., Environmental Science, Drexel University, Philadelphia, PA (1988)
Ph.D., Soil, Water, and Environmental Science, University of Arizona, Tucson, AZ (2000)

Employment

Independent Consultant: Feb 2023 - present

Research Affiliate: University of Colorado, Boulder, CO: October 2020 - present. I conduct research on the impact of abandoned wells on air, surface water, and groundwater quality.

Senior Research Scientist: PSE Healthy Energy, Oakland, CA: Jan 2017 – Feb 2023. My research focused on evaluating the impact of oil and gas development on water resources and air quality. In addition to publishing findings of my research in peer-reviewed journals and reports, I provided testimony on oil and gas development rule-making, served as an expert witness in litigation against oil and gas corporations, and have testified before Congress on the impact of oil and gas development on water resources.

Research Associate: Stanford University, Stanford, CA: Apr 2014 – May 2019. I conducted research on the impact of oil and gas development to groundwater.

Environmental Engineer: U.S. Environmental Protection Agency, Office of Research and Development, Ada, OK: Sep 1988 – Mar 2014 (retired). Duties included providing regulatory oversight assistance to

EPA remedial project managers and conducting research related to subsurface gas flow and vapor transport. Research included: (1) Development of methods to improve the effectiveness of soil vapor extraction, bioventing, and air sparging subsurface remediation systems including lead authorship of EPA's primary technical resource document in these areas; (2) Co-development of analytical solutions and associated codes for estimation of gas permeability and gas flow in soil; (3) Development of analytical solutions to simulate combined solute and vapor transport in soil including lead authorship of the model *VFLUX;* (4) Development of field methods to improve active soil-gas sampling especially pertaining to leak and purge testing; (5) Development of forensic techniques (use of hydrocarbon degradation products and radon) and assistance in development of EPA guidance to evaluate vapor intrusion (migration of organic compounds from ground water to indoor air); (6) Development of ground water and soil gas monitoring strategies including assistance in development of EPA's Class VI rule on geologic sequestration of carbon dioxide; (7) Development of methods to evaluate impact to Underground Sources of Drinking Water (USDWs) under the Safe Drinking Water Act and stray gas migration due to hydraulic fracturing. Research activities included conducting seminars, workshops, and short courses to States.

Environmental Engineer (Remedial Project Manager: U.S. Environmental Protection Agency, Region III, Philadelphia, PA: Jun 1980 – Dec. 1981 and Sep 1982 – Jan 1988. Duties included: conducting investigations (e.g., remedial investigations, risk assessments, feasibility studies, sample collection) under the Comprehensive Environmental Response and Liability Act (CERCLA) and Resource Conservation and Recovery Act (RCRA), federal contractor oversight, preparation of consent orders and initiation of enforcement actions.

Military Service: U.S. Marine Corps: Active duty 1975-1978, Camp Pendleton, CA, Honorable Discharge in 1981.

Scientific Awards

5 EPA Bronze Medals: (1) Development of EPA Guidance Document on Soil Vacuum Extraction, (2) Technical Support to EPA's Program and Regional offices on Subsurface Gas Flow and Vapor Transport, (3) Development of EPA Guidance on Vapor Intrusion, (4) Research on Vapor Intrusion, (5) Development of Class VI Rule on Geologic Sequestration of Carbon Dioxide

3 EPA Honor Awards: (1) Development of a National Risk Management Research Laboratory Strategic Research Plan, (2) Development of a Protocol to Assess Vapor Intrusion; (3) Technical support at Leaking Underground Storage Tank Sites

3 EPA Scientific and Technological Achievement Awards: (1) Innovative Design of Soil Vacuum Extraction Systems, (2) Development of Analytical Model to Simulate Transient Flux of Volatile Organic Compounds in Soil to Ground Water and the Atmosphere, (3) Simulation of Geochemical Impacts to Ground Water from Leakage of Carbon Dioxide

Peer-Reviewed Journal Publications, Reports, and Book Chapters

Tisherman, R.; Rossi, R.J.; Shonkoff, S.B.C., DiGiulio, D.C. **2023**. Groundwater Uranium Contamination from Produced Water Disposal to Unlined Ponds in the San Joaquin Valley. *Science of the Total Environment*, Vol. 904, 15 December 2023, 166937

Kang, M.; Boutot, J.; McVay, R.; Roberts, K.; Jasechko, S.; Perrone, D.; Tao T.; Lackey, G.; Raimi, D.; DiGiulio, D.C.; Shonkoff, S.B.C.; Carey, J.W.; Elliott, E.G.; Vorhees, D.J.; Peltz, A.S. **2023.** Environmental risks and opportunities of orphaned oil and gas wells in the United States. *Environmental Research Letters*, 18, 7, 074012.

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DiGiulio D.C., Ruybal C.J., Hargrove K.D., Wilkin R.T. **2018**. Leak, Purge, and Gas Permeability Testing to Support Active Soil-Gas Sampling, EPA 600/R-18/225, U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, October 2018

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Rossi, R.J.; DiGiulio, D.C. **2023**. Documenting Known Abandoned Wells in Proximity to Potential Carbon Storage Formations in Louisiana.

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DiGiulio, D.C. Rossi, R.J. **2021**. Review of Powhatan Salt Company, Solution Mining Well Permits for Storage of Natural Gas Liquids at the Mountaineer NGL Storage Facility near Clarington, Ohio, Mar 24, 2021. Report available at: https://www.psehealthyenergy.org/our-work/publications/archive/review-of-powhatan-salt-company-solution-mining-well-permits-for-storage-of-natural-gas-liquids-at-the-mountaineer-ngl-storage-facility-near-clarington-ohio/

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DiGiulio, D.C. **2020**. Evaluation of Groundwater Resource Protection in Bureau of Land Management Environmental Assessment DOI-BLM-MT-0000-2020-0004-EA in Dawson, Sheridan, and Richland counties in Montana and Burke, McKenzie, Williams, Billings, and Slope counties in North Dakota, Aug 4, 2020

DiGiulio, D.C. **2020.** Comments on Notice of Rulemaking by the Colorado Oil and Gas Conservation Commission Wellbore Integrity Rules, Mar 11, 2020

DiGiulio, D.C.; Hill, L.L.; Shonkoff, S.B.C. **2019**. Evaluation of the EPA's Draft Report on Expanding the Discharge of Produced Water to Surface Water Through the Clean Water Act, Oct 1, 2019. Report available at: https://www.psehealthyenergy.org/wp-content/uploads/2019/07/PSE-Eval-of-EPA-Draft-Report-Wastewater-Mgt-Study_7.1.19.pdf

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DiGiulio, D.C. **2018**. Examination of Groundwater Resources in Areas of Glacier, Liberty, Hill, Chouteau, Blaine, Phillips, and Valley Counties in Montana Proposed for the March 2018 BLM Lease Sale, Jan 10, 2018

DiGiulio, D.C. **2017.** Review of Montana Board of Oil and Gas Conservation Rulemaking – Hydraulic Fracturing Chemical Disclosure and Water Quality Testing, Nov 30, 2017

Recent Testimony

DiGiulio, D.C. **2022**. Oral Testimony to California State Assembly on Bill 2447: Oil and Gas Wastewater: Unlined Ponds: Prohibition, April 18, 2022

DiGiulio, D.C. **2019**. Impact of Oil and Gas Development on Groundwater Resources. Written Testimony before the Subcommittee on Energy and Mineral Resources Committee on Natural Resources, United States House of Representatives, Washington, D.C., May 16, 2019. Available at: https://www.psehealthyenergy.org/wp-content/uploads/2019/05/DiGiulio-Congressional-Written-Testimony.pdf

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DiGiulio, D.C. **2023**. Chemical Characterization of Natural Gas Leaking from Abandoned Oil and Gas Wells in Western Pennsylvania. PA League of Women Voters Shale and Public Health Conference. November 14, 2023, Pittsburgh, PA.

DiGiulio, D.C. **2023**. Federal Regulation and Technical Requirements for Onshore Geologic Storage of Carbon Dioxide. Presented at: Webinar on Carbon Capture and Storage (CCS): Risks of CO2 Leakage from Geological Reservoirs and Pipelines, Center for Applied Environmental Science, June 1, 2023

DiGiulio, D.C.; Shonkoff, S.B.C. **2019**. Risk Posed to Groundwater Resources by the Disposal of Produced Water into Unlined Produced Water Ponds in California. Groundwater Protection Council Annual Forum, San Antonio, TX, September 15-17, 2019. Available at: https://www.psehealthyenergy.org/wp-content/uploads/2019/09/DiGiulio-and-Shonkoff-2019-GWPC-Presentation.pdf

DiGiulio, D.C.; Shonkoff, S.B.C.; Jackson, R.B. **2019**. The Need for a Uniform Conservative Definition of Protected Groundwater During Oil and Gas Development. National Groundwater Association Workshop Groundwater and Oil and Gas Development: Improved Management Practices for Groundwater Protection and Water Supply. San Antonio, TX, March 4-5, 2019. Available at: https://www.psehealthyenergy.org/wp-content/uploads/2019/03/DiGiulio-et-al-NGWA-March-2019.pdf

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ATTACHMENT C

Accufacts Inc.
"Clear Knowledge in the Over Information Age"

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July 17, 2024

Attn: Earthjustice
Michelle Ghafar
50 California Street, Suite 500
San Francisco, CA 94111

Re: Observations concerning Kern County's Recent Recirculated Draft Environmental Impact Report ("RDEIR") on the TerraVault I Carbon Capture and Storage Project ("Project").

Accufacts Inc. ("Accufacts") has reviewed the latest Kern County submission for the above Project, retitled Recirculated Draft Environmental Impact Report.[1] Accufacts has the following brief major observations that are by no means an inclusive listing of the many deficiencies concerning the RDEIR:

1. **As with the original DEIR, the RDEIR is vague and misleading throughout the document and does not properly address the major shortcomings provided in previous comments submitted on the original DEIR. (See attached report submitted on the original DEIR on March 1, 2024.)**

2. **The RDEIR lists possible new sources to supply CO_2 to the Elk Hills reservior without identifying how such sources will be transported to the Elk Hill facilities—a critical omission.[2]**

3. **The addition of the CPUC process in the RDEIR should be raising serious concerns about possible efforts to move CO_2 in converted existing pipelines as a gas to circumvent the moratorium on development of intrastate gas pipelines within the state.[3]**

How additional CO_2 sources will be transported to the Elk Hills facilities, and in what phase (i.e., gas or liquid), is an important safety jurisdiction matter for such pipelines. Severe deficiencies in current CO_2 pipeline safety regulations, both at the federal and state level, leave major regulatory safety gaps needed to protect the public from this mode of CO_2 pipeline transportation, liquid or gas. Pipeline safety regulations are even weaker for CO_2 gas phase pipelines (new or converted

[1] Kern County Planning and Natural Resources Department, "Recirculated Draft Environmental Impact Report, Volumes 1 and 2," June 2024.
[2] *Ibid.,* Volume 1, p. 4.11-53 & 4.11-54.
[3] *Ibid.,* Volume 1, p. 4 – 11 to 54.

existing) than that for liquid CO_2 pipelines. The RDEIR remains incomplete regarding these important details.

As in the original DEIR, the Project continues to disregard badly needed safety regulatory efforts, either at the state or federal level, before prudent safety regulations can be developed and implemented.



Richard B. Kuprewicz,
President,
Accufacts Inc.

Attachment A
to Technical Comments of Richard Kuprewicz:
February 26, 2024 Technical Comments of
Richard Kuprewicz

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February 26, 2024

Attn: Earthjustice
Michelle Ghafar
50 California Street, Suite 500
San Francisco, CA 94111

Re: Observations concerning Kern County's Draft Environmental Impact Report ("DEIR") on the TerraVault I Carbon Capture and Storage Project ("Project").

A. Summary of DEIR.

The above referenced DEIR makes many statements that are confusing or misleading, lacking critical information to allow decision makers, including the public, to make an informed evaluation and decision about the proposed Project from this document. It appears that many of these statements relate to safety jurisdiction of various agencies, which based on my extensive experience, are confusing, if not misleading. It appears that the Project is getting ahead of badly needed safety regulatory efforts, either at the state or federal level before prudent safety regulations can be developed and implemented. Section 3 below identifies eight areas where the DEIR needs to be supplemented with important details before this Project is allowed to proceed. Lack of such detail has served to be a recurring problem across the U.S. as states and local governments wrestle with serious gaps in pipeline safety regulations for CO_2 pipelines as a result of an onslaught of multibillion dollar proposals incentivized by recent federal tax credits. A 2022 paper identifies at least eight serious deficiencies in current federal minimum pipeline safety regulations concerning liquid CO_2 pipelines summarized as follows:[1]

1. The definition of carbon dioxide needs to be updated.
2. Scientifically based regulation on impact areas for CO_2 pipeline ruptures needs to be promulgated.
3. Regulatory reference to industry recommended practices should be avoided.
4. Fracture propagation protection on CO_2 pipelines needs to be codified.
5. The use of odorant in CO_2 pipelines should be mandated.
6. Pipeline operations and maintenance manuals should require specific coordination with local emergency response personnel.
7. Maximum contaminant impurities for CO_2 pipelines should be specified.
8. Regulations for conversion of existing pipelines to CO_2 service should be developed.

[1] Richard B. Kuprewicz, President of Accufacts Inc., prepared for the Pipeline Safety Trust, "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," March 23, 2022, pp. 12 &13.

B. The TerraVault 1 Carbon Capture and Storage Project DEIR - a simple synopsis.

The TerraVault 1 Project proposes to capture CO_2 from the existing Elk Hills oil field, produced by separating a portion of the pre-combustion field gas production into "high-purity" CO_2 streams at two existing or relocated cryogenic and fractionation natural gas plant facilities identified as "CGP-1." The term high purity is not defined in the DEIR, but is a critical parameter given that existing federal minimum pipeline safety jurisdiction currently establishes a CO_2 purity of more than 90% in a poorly worded definition of carbon dioxide.[2]

The high-purity CO_2 streams will then be transported from the two CGP-1 processing/treating locations by "Facility Pipelines" which will be newly constructed pipelines.[3] The DEIR also uses the term Injection Pipelines. The definition of both Facility Pipelines and Injection Pipelines needs to be clarified as well as their transition boundaries as these terms have specific meaning in the industry and affect regulatory safety jurisdictions, if any, of various federal and state agencies that might become involved.

The DEIR indicates that new pipelines of up to 16-inches in diameter, approximately 5.61 miles long for phase 1, and approximately 7.59 miles long for phase 2, will transport CO_2 to six injection wells at two sequestration reservoir sites within the site plan (to 26R Monterey Formation Reservoir at an approximate depth of 6,000 feet for phase 1's four injection well sites, and to A1-A2 Monterey Formation Reservoir, approximately 8,500 feet deep for phase 2's two injector well sites).[4]

C. Critically important and needed pipeline information is missing in the DEIR.

Important pipeline information is missing in the DEIR that will not permit decisionmakers to make an informed decision about this Project. For example, some of the many major shortcomings in the DEIR related to pipeline issues are:

1. The purity of the claimed "high-purity" CO_2 stream has not been provided.

The CO_2 purity sets a simple bar as to whether the Pipeline and Hazardous Materials Safety Administration, or PHMSA, the federal agency chartered with transportation pipeline safety regulations, or for that matter the California Office of the State Fire Marshal, or OSFM, the state agency chartered with intrastate liquid transportation pipeline safety oversight in California, has any pipeline safety jurisdiction under current transportation pipeline safety regulations. The DEIR needs to provide the minimum purity of the CO_2 stream for reinjection and how this minimum will be controlled/maintained and assured. If the CO_2 purity is not above 90 %, the pipeline facilities are not regulated as transportation pipelines under current federal pipeline safety regulations.

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[2] 49CFR§195.2 Definitions - *Carbon Dioxide*.
[3] DEIR, Volume 1, pp. 3-18 & 3-19.
[4] DEIR, Volume 1, pp. 3-21 & 3-22.

Since the CO_2 will be produced from the oil/gas field, the DEIR also needs to present how possible impurities in the CO_2 stream will be limited and controlled. This is especially important for water as water in CO_2 pipelines is not tolerated well in carbon steel pipeline systems. Water in such CO_2 systems can experience extremely unpredictable and high corrosion rates that can quickly result in pipeline rupture failure.

2. **The DEIR discussion of Facility Pipelines and Injection Pipelines is not clear.**

   Facility Pipelines and Injection Pipelines usually have special meaning/distinction within the industry and whether any pipeline safety agency has any jurisdiction. The DEIR is very confusing on this important issue, labeling for example Injection Pipelines under the heading Facility Pipelines in the figures' legends.[5] PHMSA, or for that matter the OSFM, may not have any jurisdiction on this Project or parts of this Project.

3. **The DEIR indicates that the Facility Pipelines will operate at pressures roughly 1,700 to 2,100 psig for "dense phase" transport.[6]**

   Psig, or pounds per square inch gauge, is a pressure measurement used in the industry. The pressure range for this system, while higher than conventional liquid transportation pipelines, is not unusual for dense phase CO_2 pipelines. Dense phase is a term used to mean either liquid **or** supercritical CO_2 phase for a liquid pipeline, and is not defined in either Federal or California pipeline safety regulations.[7] What phase a specific CO_2 liquid pipeline segment is in (liquid or supercritical) at the time of a pipeline rupture can have a significant impact on rupture release dynamics, the tonnage of pipeline inventory that will be vented even after mainline valves are closed, and associated attempts to model possible rupture impact zones and attempts at establishing realistic safety buffer zones.

4. **The DEIR does not provide important pipeline parameters.**

   At this stage of the Project, the pipeline operator should be able to provide the pipeline specifics such as: pipe grade, thickness, diameter, and maximum operating pressure, or MOP, a term defined in federal pipeline safety regulation having a specific meaning related to pipeline safety. As previously mentioned, the DEIR should also clearly delineate the general pipeline route, possible pipeline safety jurisdictional boundaries, and approximate location of main equipment such as pump/compressor stations. The lack of such basic information makes it difficult to determine a simple process flow scheme for the Project. This lack of such basic information also prevents decisionmakers from assessing impacts and to develop feasible mitigations for the Project. Not only does the DEIR lack such critical basic pipeline information, what information is supplied is also confusing. It appears the Project is being rushed and

[5] DEIR, Volume 1, p. 3-20, Figures 3-8 and 3-9, Location of Phase 1 Wells: 373-35R, 353X-35R, 345-36R, and 363-27R, and Location of the Phase 2 Wells: 357-7R and 355-7R, respectively.
[6] DEIR, Volume 1, p. 3-16.
[7] 49CFR§195 and California Code, Chapter 5.5. The Elder California Pipeline Safety Act of 1981.

missing basic information to permit independent evaluation and verification of the Project.

5. The location of compressor equipment is not well defined.

The DEIR states "Two new CO_2 compressor packages are proposed for installation at the facility. Compressors would be of the reciprocating type and driven by electric motors."[8] The general location and specific phase of the CO_2 feeding into such equipment is very important to the safe operation of the system and, more importantly, the compressors. One way to blow up a reciprocating compressor is to inadvertently introduce liquid into the compressor. I cannot determine from the limited and confusing information provided in the DEIR whether the location of the proposed compressors will be safely placed within the system to assure liquid CO_2 cannot be inadvertently introduced into the compressors.

6. The placement of mainline valves along the pipelines are not defined.

The DEIR states: "New valves would be installed based on regulatory and owner requirements."[9] As should become obvious from reading this report, such important valve determinations have not been clearly defined, so this DEIR citation is meaningless. Also, the DEIR does not identify whether mainline valves will be manually operated or remotely operated. Manually operated valves can take considerable time to reach and then close (especially for larger diameter pipelines such as a 16-inch mainline valve) increasing the tonnage of CO_2 released upon pipeline rupture.

As a point of reference, a 16-inch diameter CO_2 pipeline, depending on whether the CO_2 inventory is in a supercritical or liquid phase and its associated density, will release approximately 110 to 200 tons per mile of CO_2 upon a pipeline rupture once pipeline mainlines have been closed. What makes transportation pipelines unique, especially for CO_2, is the amount of tonnage undergoing phase change from cooling, that can be de-inventoried from a ruptured pipeline, releasing tons of CO_2 between mainline valves once such valves have been closed. The lack of timely closure of valves was a significant contributing factor for the Satartia, MS rupture CO_2 release as discussed later in this report.

7. The CO_2 temperature along the pipelines is not provided.

An important variable in the DEIR, approximate CO_2 temperature along the pipelines, dictates the CO_2, whether liquid or supercritical phase (which can change) along the pipelines as temperature changes at the expected pipeline operating pressure. This important temperature parameter is not mentioned nor discussed anywhere in the DEIR. What phase a segment of a pipeline is transporting CO_2 in can have serious significance on issues such as safety jurisdiction, design/operation, and pipeline rupture

[8] DEIR, Volume 1, p. 3-17.
[9] DEIR, Volume 1, p. 3-18.

release dynamics and safety buffer zones. For example, current federal minimum pipeline safety regulations do not regulate pipelines operating in liquid CO_2 phase. I have previously mentioned the importance of assuring that reciprocating compressors do not inadvertently receive liquid. Without understanding the initial phase CO_2 will most likely be in in a specific pipeline segment, attempts to establish safe buffer or impact zones are meaningless. Two temperature extreme boundary cases for CO_2 are usually necessary; a high temperature season and a low temperature season to assist in defining the range of CO_2 phases (liquid or supercritical), and associated release modeling/pipeline buffer safety margins for the operation.

8. The DEIR misses the importance of CO_2 phase.

The DEIR also misses the important differences associated with varying phases of CO_2 in a liquid pipeline operation that are not properly addressed in current pipeline safety regulations, leaving such pipelines basically unregulated in many critically important areas. While the DEIR attempts to address certain environmental impacts related to the Project, the real issue relates to pipeline safety and the possible impact to public safety. The DEIR is incomplete in this important area and needs to be supplemented with this missing information before this Project can move forward.

While not mentioned in the DEIR, at the expected pressures and temperatures of the proposed Project's pipelines, I would anticipate the Project's pipelines to be operated in either liquid CO_2 or supercritical CO_2 phases, with the phases changing somewhat with time depending on the temperature of the buried pipelines. Whether a pipeline segment is liquid or supercritical phase at the time of rupture affects the expected phase change occurring at the rupture site, the rate of release, the tonnage that will be released between closed valves, and expected buffer impact zones.

D. The California OSFM is limited in what pipeline safety regulations it can enforce for intrastate liquid carbon dioxide transportation pipelines.

Despite the best of recent intentions to enact improvements in carbon dioxide pipeline safety regulations within California, the California Legislature has failed to pass meaningful improvements in pipeline safety regulations as it applies to intrastate carbon dioxide pipelines. Without such new legislation, the California OSFM can only implement and enforce pipeline safety regulations for intrastate CO_2 liquid pipelines within the state as codified in federal minimum pipeline safety regulations (49CFR§195) intended for liquid transportation pipelines. Based on my extensive experience in California liquid pipeline operation and many pipeline investigations within the state, it is my understanding that the OSFM can only enforce federal pipeline safety regulations for CO_2 liquid pipelines codified in current federal regulations.

Federal regulations for carbon dioxide pipelines are currently woefully inadequate as discussed in more detail in my recently referenced March 23, 2022 CO_2 public paper. In addition, announcements by PHMSA to move forward with carbon dioxide safety regulations may miss many of the safety issues and concerns related to carbon dioxide liquid pipelines

which can take some time to properly address, given the highly unusual restrictive regulatory process imposed on PHMSA.[10]

E. The DEIR attempts to minimize the impact of the Satartia rupture on the public.

Some additional information might be helpful to add to the February 22, 2020 Satartia, MS 24-inch pipeline rupture discussion in the DEIR.[11] Depending on the density one assumes in the pipeline, the rupture released 3,000 to 5,000 tons of carbon dioxide after the mainline valves were eventually closed on the 24-inch pipeline, which took considerable time to isolate the ruptured segment**.** The CO_2 plume went beyond the Town of Satartia, crossing the Yazoo River, extending well over a mile from the pipeline release site which was basically downhill from the rupture releasing heavier than air CO_2. The DEIR fails to mention that the Town of Satartia was not identified as a high consequence area in the pipeline operator's integrity management program and the air dispersion model was unfit for the 24-inch pipeline. The high rain situations and steep terrain should not come as a surprise in this challenging location, and the wording in the DEIR appears to try to downplay that the rupture threat was a unique situation in that area of Mississippi. PHMSA's corrective action order requiring review of geohazard potential along the pipeline should dispel any illusion that breakaway landslide was an unusual threat. Despite the release of a PHMSA Advisory following the Satartia rupture, PHMSA knows that there have been pipeline regulations in effect for many decades that place the responsibility on the pipeline operator to monitor their pipeline right-of-way for signs of possible abnormal loading such as massive landslide potential (what is known in the industry as a breakaway landslide threat) that can easily result in pipeline rupture.[12]

F. Well Blowout prevention and Aliso Canyon similarities.

While not a specific pipeline associated matter, I have an ethical responsibility to note that the DEIR does not address the possibility of a CO_2 injection well blowout on any of the six proposed CO_2 injection wells. In late 2015, California was associated with an underground natural gas storage well blowout, the Aliso Canyon failure, that released well over 100,000 tons of natural gas which is normally lighter than air as compared to CO_2 which is heavier than air. The Aliso Canyon failure demonstrated to the public some of the risk of large high pressure underground storage reservoirs. I would advise that the Project incorporate some form of well blowout prevention design to prevent release of massive quantities of heavier than air CO_2 from the underground reservoirs should an injection well experience a blowout. The safety design should incorporate an approach with prudent independent safeties to assure that the installation will actually work and stop the release of CO_2 from the high-pressure reservoir if a well blowout occurs. Without getting into specific design issues, there are various ways to approach this possible threat, such as incorporating an automatic subservice safety valve as a blowout preventor on each injection well. The tonnage of CO_2 released from a well blowout

[10] "PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak," May 26, 2022 at PHMSA website: https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.
[11] DEIR, Volume 1, pp. 4.9-8 & 4.9-9.
[12] PHMSA updated ADB-2022-01, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," June 2, 2022.

can easily exceed, by many orders of magnitude, the tonnage of CO_2 released from a pipeline rupture. As history has often demonstrated, well blowouts can release many thousands of tons from essentially an infinite supple of CO_2 in the reservoir, easily surpassing pipeline rupture releases.

G. Background/Experience.

Accufacts was asked to review the DEIR for the Project recently released in December 2023.[13] I have over fifty years of experience in the energy industry, including almost 25 years as president of Accufacts Inc. ("Accufacts"). Accufacts provides independent expert consulting services to assist decision makers in making informed decisions concerning pipelines. Pipeline safety expertise is provided in areas including, but not limited to; pipeline failure investigation, risk management, siting, construction, design, operation, maintenance, training, control room management including Supervisory Control and Data Acquisition ("SCADA") approaches, leak/rupture detection, integrity management, emergency response, and pipeline safety regulatory development and compliance. Much of my background is grounded in pipeline incident investigations following numerous pipeline rupture tragedies spanning several decades.

For the past two decades I have been involved as a representative of the public, which carries special obligations to avoid a conflict of interest, in advancing pipeline safety regulations at the federal and various state levels as demonstrated by my CV. For example, I played a significant role representing the public in developing integrity management federal pipeline safety regulations in the early 2000s for both liquid and gas transmission pipelines. These regulatory approaches emulated a safety process approach that I instituted and developed for the City of Bellingham, WA. This process, identified as the Safety Immediate Action Plan, or SIAP, identified steps that the pipeline operator was to complete following the Bellingham rupture tragedy of June 10, 1999, before that pipeline could be permitted to be returned to service.

H. Conclusion.

The DEIR is seriously incomplete and deficient in many areas as discussed above. These deficiencies need to be properly addressed before a DEIR can be deemed complete and sufficient for the Project to move forward. It is my understanding that the County can require that such critical information related to pipeline safety and CO_2 pipelines can be ordered to be provided, or supplemented, before this Project can be allowed to move forward.

Richard B. Kuprewicz, President, Accufacts Inc. Richard B. Kuprewicz

[13] Draft Environmental Impact Report – SCH# 2022030180 Volume 1, Chapters 1 through 12, CARBON TERRAVAULT I (KERN COUNTY) by California Resources Corporation (PP22405) at: https://psbweb.kerncounty.com/planning/pdfs/eirs/ctv1/CTV1_DEIR_Vol_1_Ch_1-12_upd.pdf, and Draft Environmental Impact Report – SCH# 2022030180 Volume 2, Appendices A-K, CARBON TERRAVAULT I (KERN COUNTY) by California Resources Corporation (PP22405) at: https://psbweb.kerncounty.com/planning/pdfs/eirs/ctv1/CTV1_DEIR_Vol2.pdf, December 2023.

Attachment B
to Technical Comments of Richard Kuprewicz:
Qualifications and Experience

Curriculum Vitae.

Richard B. Kuprewicz

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Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:

Accufacts Inc. **1999 – Present**

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties:
> Full business responsibility
> Technical Expert

Alaska Anvil Inc. **1993 – 1999**

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties:
> Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc. **1991 - 1993**

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties:
> Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co. **1989 – 1991**

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties:
> Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co. **1985 – 1989**

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

Position: Vice President and Manager of Operations
Duties:
> Full operational responsibility
> Major ship berth operations
> New acquisitions
> Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln **1985**

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

Position: Plant Manager
Duties:
> Team building of new facility that had been failing
> Plant design modifications and troubleshooting
> Setting expense and capital budgets, including key gas supply negotiations
> Modification of steam plant, power generation, and environmental controls

Arco Products Co. **1981 - 1985**

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

Position: Operations Manager of Process Services
Duties:
> Modernize refinery utilities and storage/blending operations
> Develop hydrocarbon product blends, including RFGs
> Modification of steam plants, power generation, and environmental controls
> Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co. **1977 - 1981**

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

Position: Manager of Refinery Planning and Evaluation
Duties:
> Establish monthly refinery volumetric plans
> Develop 5-year refinery long range plans
> Perform economic analysis for refinery enhancements
> Issue authorization for capital/expense major expenditures

Arco Products Co. **1973 - 1977**

Operating Supervisor and Process Engineer for various major refinery complexes.

Position: Operations Supervisor/Process Engineer
Duties:
> FCC Complex Supervisor
> Hydrocracker Complex Supervisor
> Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Served for over fifteen years as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)	Pepperdine University, Los Angeles, CA
BS Chemical Engineering (1973)	University of California, Davis, CA
BS Chemistry (1973)	University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.

2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.

3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.

4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.

5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.

6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.

7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.

8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.

9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.

10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.

11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.

12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.

13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.

14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.

15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.

16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.

17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.

18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. “Observations on the Keystone XL Oil Pipeline DEIS,” prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.

20. “PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline,” prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.

21. “The State of Natural Gas Pipelines in Fort Worth,” prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.

22. “Accufacts’ Independent Observations on the Chevron No. 2 Crude Oil Pipeline,” prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.

23. “Accufacts’ Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline,” prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.

24. “Accufacts’ Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ,” prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.

25. “Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E’s Pipeline Safety Enhancement Plan,” submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.

26. “Evaluation of the Valve Automation Component of PG&E’s Safety Enhancement Plan,” extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B.Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.

27. “Accufacts’ Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project,” prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.

28. “Accufacts’ Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ,” prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.

29. “Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming,” prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.

30. “Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery,” prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.

31. “Analysis of SWG’s Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005,” prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.

32. “Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria,” prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.

33. “Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas,” prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.

34. “Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.

35. “Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline’s Northeast Upgrade Project,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. “Report on Pipeline Safety for Enbridge’s Line 9B Application to NEB,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.

37. “Accufacts’ Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria,” prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.

38. “Accufacts’ Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing,” prepared by Richard B. Kuprewicz, November 25, 2013.

39. “Accufacts Inc. Evaluation of Transco’s 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.

40. Accufacts report “DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks,” prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.

41. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.

42. Accufacts’ “Evaluation of Actual Velocity Critical Issues Related to Transco’s Leidy Expansion Project,” prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.

43. “Accufacts’ Report to Portland Water District on the Portland – Montreal Pipeline,” with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 1014.

44. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.

45. Review of Algonquin Gas Transmission LLC’s Algonquin Incremental Market (“AIM Project”), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d,” prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.

46. Accufacts’ Key Observations dated January 6, 2015 on Spectra’s Recent Responses to FERC Staff’s Data Request on the Algonquin Gas Transmission Proposal (aka “AIM Project”), FERC Docket No. CP 14-96-000) related to Accufacts’ Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.

47. Accufacts’ Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

48. Accufacts’ Report on Atmos Energy Corporation (“Atmos”) filing on the Proposed System Integrity Projects (“SIP”) to the Mississippi Public Service Commission (“MPSC”) under Docket No. 15-UN-049 (“Docket”), prepared by Richard B. Kuprewicz, dated June 12, 2015.

49. Accufacts’ Report to the Shwx’owhamel First Nations and the Peters Band (”First Nations”) on the Trans Mountain Expansion Project (“TMEP”) filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.

50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ (“Township”), to the Township of Chesterfield, NJ, dated February 18, 2016.

51. Accufacts Report, “Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7,” dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).

52. Accufacts Report, “ A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.

54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.

55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.

57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.

58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.

59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.

60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.

61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.

62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.

63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.

64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.

65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.

66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.

67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, “Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station (“Event”), Boot Road, West Goshen Township, PA,” dated September 16, 2019.

69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.

70. Report to West Goshen Township Manager, Mr. Casey LaLonde, “Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township,” dated July 23, 2020.

71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas’ sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.

72. Report to Natural Resources Defense Council, Inc., “Accufacts’ Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements,” October 1, 2020.

73. Report to Pennsylvania Public Utilities Commission (“PAPUC”), “Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations,” dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.

74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.

75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.

76. Report to Pipeline Safety Trust and Bold Alliance, “Accufacts’ Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.,” March 23, 2022.

77. Accufacts Inc., Public Presentation For the National Academies of Science Engineering Medicine and The Transportation Research Board, “To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines,” 4/27/22.

78. Accufacts Inc, “6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO_2 Transmission Pipeline Releases,“ 6/13/22.

79. Accufacts Report for Pipeline Safety Trust, “Safety of Hydrogen Transportation by Gas Pipelines,” 11/28/22.

80. Completed a series of testimonies related to Enbridge’s Line 5 proposal to replace 2 – 20-inch diameter existing submerged pipelines currently lying across the bottom of the Straits of Mackinac with a 30-inch diameter grade X-70 pipeline, proposed to be installed in a 21-foot diameter concrete tunnel to be installed across the approximate 4 mile span of the Straits of Mackinac. Testified on Behalf of the Bay Mill Indian Community before the State of Michigan Public Service Commission, Docket U-20763, in opposition to this very poorly designed proposal/installation allowing for movement of the pipeline on rollers within the tunnel. Final testimony to the docket submitted May 19, 2023. This is the only pipeline proposal I am aware of in the world that would place a crude oil and liquid propane pipeline, especially a 30-inch diameter pipeline, within a tunnel.

81. Issued to Ms. Niroop Srivatsa, City Manager, “Accufacts Report for the City of Lafayette on the Status of the Tree Assessment Process with PG&E,” indicating most of the trees identified for removal by PG&E risk management

approach have nothing to do with gas pipeline safety, June 15, 2023.

82. Issued Direct Testimony to Illinois Commerce Commission (“ICC”) on the Navigator Heartland Greenway LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0161, on behalf of Citizens Against Heartland Pipeline (“CAHGP”), McDonough County, Christian County and Hancock County (the “Counties”) (jointly, “Citizen and County Intervenors” of “CCI”), raising serious questions as to PHMSA’s recent assertions of pipeline safety jurisdiction, and underscoring the ICC’s authority for pipeline siting jurisdiction of said pipeline proposal in the State of Illinois, filed June15, 2023.

April 9, 2024

David Albright
Manager, Groundwater Protection Section
United States Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, CA 94105-3901

RE: Request for Additional Information - 3/29/2024
Aera Energy LLC (Aera) - CarbonFrontier
Underground Injection Control (UIC) Permit Application
Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY23-1.1 to 1.9

Dear Mr. Albright,

Aera Energy LLC (Aera) has prepared a response to the U.S. Environmental Protection Agency (EPA) Region 9's technical review comments for the Site Characterization and Area of Review (AoR) Delineation Modeling sections for the subject permit application. Please find the responses in the two enclosures to this letter – one for Site Characterization and one for AoR Modeling. Additionally, the Application Narrative and Attachment B (AoR Modeling and Corrective Action Plan) have been updated in response to EPA's questions and comments and submitted to the GSDT. As requested, we have included clean versions of the updated documents as well as versions which retain tracked changes for comparison. We hope that this helps to facilitate your review.

Please contact me at (661) 665-5000 or by email (bjgentry@aeraenergy.com) if you have any questions or if any additional information is needed.

Sincerely,



Beau Gentry, *Carbon Team Supervisor*

Aera Energy LLC

Enclosures: Response to Request for Additional Information - Site Characterization Evaluation

Response to Request for Additional Information - AoR Delineation Modeling Evaluation

cc w/enclosures: Kaylee Glenney, EPA Region 9

Randy Hoyle, Aera Energy LLC

ENCLOSURE
Request for Additional Information
Site Characterization Evaluation
Aera Energy, LLC CarbonFrontier Project
Underground Injection Control (UIC) Permit Application
Class VI Pre-Construction Permit Application No. 9UIC-CA6-FY23-1.1 to 1.9

This document provides a review of information submitted by the Aera Energy, LLC (Aera) December 6 and December 21, 2023, in response to an EPA Request for Additional Information (RAI). EPA solicited additional details regarding the site characterization information in Aera's March 2023 Underground Injection Control (UIC) Class VI permit application for a geologic sequestration (GS) project (CarbonFrontier) in the Belridge oil fields in Kern County, CA. The review below includes EPA's original questions which are bolded, Aera's responses in normal font, and comments on Aera's responses in italicized font. Previous responses that require no further information are not included in this enclosure. Please note that modifications to the model parameters may be needed if pre-operational testing yields results that are significantly different than the model inputs described in the initial permit application.

1. **Larger Slip Tendency (Ts) values were observed on the southeast side of the AoI, indicating that the faults are less stable than those to the north. Provide further clarification that the proposed CO_2 injection will have limited effects on fault stability in the southeast side of the AoI and the increased slip tendency is unlikely to be "ready- to-slip."**
    a. **In addition, please comment on the potential for fault reactivation if pore-fluid pressure increases due to CO_2 injection in the southeast area of the AoI. As slip on existing faults could facilitate a risk to CO_2 storage integrity, it is suggested that aspects surrounding in situ stress conditions (both regional and local) are critically assessed during site appraisal.**

Aera's Response:
The fault stability analysis (FSA) performed for the Application Narrative Version 2 (submitted to GSDT March 10, 2023) calculated Slip Tendency (Ts) values across the faults, including the southeast side of the AoI, were less than 0.8, where a value of 1.0 would indicate slippage. The proposed injection of CO_2, therefore, is unlikely to cause the faults, even in the southeast area, to be "ready-to-slip."

A three-dimensional (3D) analytical geomechanical model was developed to further study the effects of pore pressure and stress changes due to CO_2 injection and is presented in the revised Area of Review and Corrective Action Plan (Attachment B Version 2) and the revised Section 2.5 of the Application Narrative Version 3, both submitted to GSDT separately. A new FSA was performed using the 3D geomechanical model and has confirmed that the slip tendency of the faults will not rise to a value that would indicate that they are "ready-to-slip". The maximum Ts values (referred to in the new analysis as stress levels) are presented below, described in detail in Attachment B Version 2 and summarized in Section 2.3.3.2 of the Application Narrative Version 3.

Maximum Stress Levels to Evaluate Fault Reactivation

Maximum Injection Pressure (psi)	Fault Shear Stress Level	Fault Tensile Stress Level
Base Case: 4,750	0.58	0.67
Upper Limit Case: 4,940	0.58	0.69

Comments:

The applicant has conducted a new fault stability analysis (FSA) using a 3D geomechanical model. The objective is to address any potential effects from pressure buildup on fault stability. In general, it is good practice to locate CO_2 injection wells as far as possible from faults. In the case of a highly faulted area such as the CarbonFrontier project, evaluation of the potential for fault reactivation via an FSA is important to ensure that the integrity of the CO_2 storage facility is not compromised.

The applicant's new FSA indicates that the slip tendency (Ts) values for the faults will not rise high enough to indicate that they are "ready-to-slip" (i.e., having a Ts value > 1.0). The maximum Ts values (referred to in the new analysis as stress levels) were reported as 0.58 (Fault Shear Stress Level) and 0.69 for both the Base Case of 4,750 psi and Upper Limit case of 4,950 psi as the maximum injection pressure.

Although the applicant's analysis is thorough and uses an appropriate method, ongoing seismic monitoring during the project will be important, even in areas with low seismic potential; information and experience are still limited regarding long-term geomechanical behavior in geologic sequestration projects. Microseismicity (~M1) has been observed at both the Decatur (IL) and Quest (Edmonton) projects (below the target formation, mainly in the basement but not in the caprock). The events began after several years of CO_2 injection (with minimal activity during the early years of injection). Long-term seismic monitoring is also important to understand the dynamic impacts from CO_2 injection associated with increased pore pressure and resulting stress changes.

The applicant has proposed installing a seismic monitoring network (consisting of 3D geophones, DAS fiber-optic cable and/or 3D surface seismic stations) to detect/monitor microseismic events > 1.0 M in real time through the injection and PISC time frames. Fiber optic cables will be installed in all injection wells. It may also be valuable to install fiber optic cables in monitoring wells, which are closer to the faults than the proposed injection wells. Because larger Ts values were observed on the southeast side of the AoI, indicating that the faults are less stable here than those to the north, this may be a particularly suitable location for installing fiber optic (DAS) monitoring. As the project progresses and operational and monitoring data are collected, new considerations may arise that can be evaluated at the 5- year interval.

Questions/Requests:

Clarify how the shear stress values and tensile stress values given above (for the Base and Upper Limit Cases of maximum injection pressures of 4,750 psi and 4,950 psi) relate to the fault slip tendency (given that Ts is the ratio of shear to normal stress) and whether any coefficient of

friction and cohesive strength values were assigned.

RESPONSE:

The 3D analytical geomechanical model developed in CMG-GEM was utilized to inform fault stability and used the definitions of fault shear stress level (FSSL) and fault tensile stress level (FTSL) as outlined below and detailed within the Appendix B-1 of Attachment B.

$$FSSL = abs\left({}^{T}/_{T_{fail}}\right)$$

$$FTSL = abs\left({}^{Pressure}/_{(\sigma'_n + Pressure)}\right)$$

Where,

T = shear stress estimated from its constituting blocks' effective stress tensors

$$T_{fail} = \sigma'_n (\tan \emptyset_{fault}) + Coh_{fault}$$

σ'_n = Normal effective stress on fault's plane
$\emptyset_{fault}$ = Friction angle
Coh = Cohesion, psi
Conservative values were used for both coefficient of friction and cohesive strength. Within the model, the friction angle value assumed is 31°, thus deriving the coefficient of friction as 0.6 i.e. tan (friction angle). The fault cohesive strength is assumed to be zero within the model, again, which is a conservative estimate discussed in section 2.3.3.2 of the Application Narrative.

The definition of Slip tendency within CMG-GEM is as below:

$$T_S = {}^{\tau_{max}}/_{(Coh + (\sigma'_n * Slipfric))}$$

Where,

τ_{max} = maximum tangential/shear stress on a fault surface

Slipfric = Mobilized fault friction, which is a linearly varying function with respect to slip displacement when below a critical displacement value; or a constant value function of a minimum fault friction when slip displacement is above critical displacement value.

Based on these definitions within CMG-GEM, the following factors were considered in deciding which fault analysis to utilize:

1. **FSSL and FTSL compute the normalized values of shear and tensile stresses which are directly indicative of whether the stresses reach a critical value of failure. FSSL and FTSL greater than 1 would lead to failure of fault stability by fault reactivation. Whereas, the slip**

tendency value, based on the above definition from CMG-GEM, is only indicative of changes in the shear stress levels and not indicative of fault reactivation mechanism.

2. **The slip tendency definition from CMG-GEM is more appropriate to be used directly for inferential purposes when the orientation of the fault plane and grid direction are aligned in the same direction. Faults in the model are not aligned with the corner-point grid direction as per the reported azimuth and dip angles of the faults. Slip tendency calculations in this scenario would result in lower values and misrepresent the risk of fault reactivation at a particular stress state.**
   Therefore, Aera used FSSL and FTSL definitions within CMG-GEM rather than slip tendency as a direct and more accurate indicator of risk towards fault reactivation.

No alterations have been made to the Application Narrative or Attachment B in response to this comment.

2. **Thermal stress resulting from injection of cold or warm fluid into a rock mass can also affect fault stability in the near-well region. The combined effects of pore pressure and thermal stresses can be examined by coupled flow-geomechanical models Where stress-magnitude parameters are uncertain, the analysis may use large differential stresses providing a conservative approach to fault stability analysis. Please discuss this issue and any relevant work done or planned.**

Aera's Response:

The thermal effects were not studied at the time of the submission of the Attachment B Version 1 (submitted to GSDT on January 19, 2023) or the Application Narrative Version 2 (submitted to GSDT on March 10, 2023). Thermal effects have subsequently been evaluated using the revised reservoir simulation model and geomechanical analysis, as described in the Application Narrative Version 3 (to be submitted to the GSDT separately) and Attachment B Version 2 (to be submitted to the GSDT separately). A simulation case using 4,750 pounds per square inch (psi) reservoir pressure and 180° F CO_2 injection stream was used in the 3D analytical geomechanical model and resulted in tensile and shear stresses below the levels indicative of inducing fractures in the reservoir or causing fault slippage, as indicated in the tables below. Fractures in the reservoir would be indicated by stress levels of 1.00 or greater, so the stress levels experienced by the reservoir in the thermal case are below 80% of the fracture stress level.

In response to this comment, text has been added to Section 2.5 of the Application Narrative Version 3 and Attachment B Version 2.

Maximum Stress Levels to Evaluate Reservoir Rock Integrity

Maximum Injection Pressure (psi)	CO_2 Injection Stream Temperature (F)	Formations	Shear Stress Level	Tensile Stress Level
4,750	180	U Sandstone	0.59	0.79
		W Sandstone	0.60	0.79

Maximum Stress Levels to Evaluate Fault Stability

Maximum Injection Pressure (psi)	CO_2 Injection Stream Temperature (F)	Shear Stress Level	Tensile Stress Level
4,750	180	0.65	0.68

Comments:
The response is generally adequate with additional clarification. The revised narrative states, "Thermal effects on fault stability were evaluated in the 3D geomechanical model by using the thermal option in CMG-GEM with a CO_2 stream injection temperature of 180^0 F. This sensitivity case resulted in a maximum shear and tensile stress levels of 0.65 and 0.68, indicating the bounding faults remain stable when considering temperature effects" (Section 2.3.3.2 of Narrative).

Thermal stress resulting from injection of either cold or warm fluid into a rock mass can affect fault stability in the near-wellbore region and can result in stress conditions moving closer towards failure.

Questions/Requests:
- *Was the case of cold CO_2 injection evaluated in addition to the warm 180^0 F injection fluid case in the coupled thermal-geomechanical simulations? Please include this evaluation or provide justification for why it wasn't done.*

RESPONSE:

The geomechanical model's sensitivity to a range of injection temperatures from 135˚F to 216˚F are included within the updated text of section 1.7.1 of Attachment B Version 3 (to be submitted to the GSDT). The sensitivities illustrate the maximum shear and tensile stress levels within the reservoir rock system and on the faults at the corresponding CO_2 injection temperatures. These results indicate that CO_2 injection temperature should remain at 180 ˚F or above to have tensile and shear stress levels below .80 and minimize thermal effects on the reservoir. A summary of the observation on stresses over the bounding faults with change in injection temperature is also included within the Fault Stability Analysis (FSA) section 2.3.3.2 and section 2.5 of the updated Application Narrative Version 4 (to be submitted to the GSDT).

3. Is Aera considering utilizing only one CO_2 injection well at a time, or do they plan to have multiple injection wells active at the same time? If the latter, have they considered the possibility of superposition resulting in increased overpressure in the 64 Zone Sandstone injection formation?

Aera's Response:
Aera is planning to inject simultaneously into the nine injection wells. The nine injection wells are

spaced such that no increased overpressure will be induced in the reservoir. For both the Attachment B Version 1 (submitted to GSDT on January 19, 2023) and the revised Attachment B Version 2 (to be submitted to the GSDT separately), the reservoir simulation model includes pressures from all nine injection wells and the maximum reservoir pressure is maintained such that it does not exceed 80% of the fracture pressure. The simulation indicates that over pressurization (exceeding 80% of the fracture pressure) does not occur at any well locations or elsewhere in the reservoir.

Furthermore, the fault stability analyses presented in both the Application Narrative Version 2 (submitted to GSDT on March 10, 2023) and the Application Narrative Version 3 (to be submitted to the GSDT separately), demonstrates that the changes in stress due to planned CO_2 injection will not cause fault reactivation in the far field. Additionally, Aera will monitor reservoir pressures and adjust well operating parameters to stay within the pre-determined fracture gradient safety range.

No modifications have been made to the Application Narrative Version 3 in response to this comment.

Comments:
The applicant has stated that they will monitor reservoir pressures and adjust well operating parameters for all nine injection wells to stay within 80% of the fracture pressure of the injection formation. It is also important not to exceed the maximum pore pressure (for both the Base Case of 4,750 psi and Upper Limit Case of 4,950 psi) to minimize the risk of induced seismicity.

RESPONSE:

Acknowledged. As described in Section 7.1, well operating parameters for all nine injection wells will be adjusted through the life of the project to adapt to downhole conditions to minimize the risk of induced seismicity. No alterations have been made to the Application Narrative Version 4 in response to this comment.

4. How many core samples, and at what depths, does Aera plan to take during drilling of the new injection wells?

Aera's Response:
As stated in the Pre-operational Testing Plan (Attachment D) Version 1 (submitted to GSDT on January 19, 2023), Aera intends to attempt the acquisition of rotary sidewall cores during drilling of new injection wells to validate observations made from core acquired in vintage wells (described in Sections 2.4.2 and 2.4.3 of the Application Narrative Version 2 [submitted to GSDT on March 10, 2023]). Rotary sidewall cores are preferred over percussion sidewall cores because of their suitability for porosity and permeability measurements. However, recovery of rotary sidewall cores can be challenging, especially considering the extent of pressure depletion in the 64 Zone Sandstones. Aera plans to collect up to 50 plug samples per well, which would be evenly distributed through the Lower Santos Shale (primary confining unit) and the 64 Zone Sandstone (injection zone) intervals to confirm observations on vertical heterogeneity. A percussion sidewall coring tool will be available as back-up to collect up to 30 samples if rotary sidewall recovery is not satisfactory. Percussion sidewall cores are not suitable for porosity and permeability

measurements, but mineralogy and lithology analyses can be performed. A subset of the samples collected (5 to 8 samples from the Lower Santos Shale and a similar number from the 64 Zone Sandstones) will be selected in each new well to perform mineralogy and petrology analyses. The specific depths of the samples for mineralogy and petrology analyses will be selected using well logs and will be located to capture vertical heterogeneity.

In response to this comment, text has been added to Section 2.4.1.4 of the Application Narrative Version 3 (to be submitted to the GSDT separately) and to the Pre-operational Testing Plan (Attachment D) Version 2 (future submittal) to provide additional detail regarding the collection and analysis of core samples.

Comments:
The response is generally acceptable. Because the W Sandstone is about 350 – 500 ft. thick, however, it is possible that more than 8 core samples for mineralogy and petrology may be appropriate for that unit depending on the heterogeneity that shows in the well logs.

RESPONSE:

Acknowledged. A larger subset of the core samples will be considered for mineralogy and petrology analysis, if warranted by heterogeneity observed in the samples or well logs. No alterations have been made to the Application Narrative Version 4 in response to this comment.

5. Does Aera agree that the neutron porosity estimates from logs are not expected to be affected from any residual hydrocarbons if present in the U and W Sandstones?

Aera's Response:
The thermal neutron log measurement is sensitive to the hydrogen index of the formation in the near-wellbore region. Liquid hydrocarbons have a hydrogen index comparable to that of connate formation water, so neutron porosity estimates are not expected to be significantly affected by residual liquid hydrocarbons. However, gas usually has a significantly lower hydrogen index than liquids (as a function of pressure and temperature), and when present within the tool's volume of investigation it can lead to an anomalously low neutron porosity reading (Schlumberger, 1989).[1] The presence of gas can have the opposite effect on the porosity estimation from the density log, overestimating porosity if using a constant fluid density value representative of brine or liquid hydrocarbons. A cross plot porosity estimation that uses both density and neutron porosity estimates is often used to account for the effects described above, as was done for the 64 Zone U and W Sandstones and presented in Section 2.4.3.1 (total porosity formula, Figure 2.4-20, and Table 2.4-4) of the Application Narrative Version 2 (submitted to GSDT on March 10, 2023).

No modifications have been made to the Application Narrative in response to this comment.

[1] Schlumberger, 1989, *Log Interpretation Principles/Applications,* Schlumberger Educational Services: Houston, Texas.

Comments:
While the response is satisfactory, the applicant should also consider comparing the listed effective porosity measurements with Nuclear Magnetic Resonance (NMR) data and core data measurements (and LWD obtained porosity with wireline obtained porosity).

RESPONSE:

Acknowledged. Aera generated a cross plot of NMR estimates for total and effective porosity using data from the 888N-12 and Gump Trust 30-1 wells near the North Belridge oil field as shown in Figure 2.4-25 in Section 2.4.3.1 of the Application Narrative Version 3 (previously submitted). These plots show that estimates of effective porosity are on average 1 to 2 porosity units lower than total porosity for the U and W Sandstones and 5 to 8 porosity units lower for the Lower Santos Shale and U Shale. It should be noted that NMR porosity estimates are sensitive to borehole rugosity, free gas saturation, and operating parameters (logging speed). No changes have been made to the Application Narrative Version 4. These comparisons will also be made with new data collected during well construction.

6. How well do the original, upscaled, and modeled porosity density distributions agree?

Aera's Response:
After submission of the Application Narrative Version 2 to GSDT on March 10, 2023, updates were made to the geomodel properties. In the latest version of the geomodel, which is represented in the Application Narrative Version 3 (to be submitted to the GSDT separately), distributions of original porosity logs, upscaled logs, and modeled porosity are generally concordant. Original and upscaled porosity distributions are consistent, while the modeled porosity distribution has a slight bias toward lower porosity values(a shift of approximately 1 porosity unit from original and upscaled well logs), which may be attributable to interpolation and extrapolation of the input log data**.**

Text and figures have been added to Appendix 2B of the Application Narrative Version 3 to describe and display the correlations.

Comments:
In Figure 8 (PDF page 325), the well logs, upscaled cells, and the geocellular model appear fairly concordant for the U and WW sandstones, but not for the Lower Santos Shale and U. Shale. There are significant spikes in the well logs that are not represented in the upscaling or geomodel.

Questions/Requests:
Please clarify the source and interpretation of the spikes in the log-based porosity for the shales in Figure 8.

RESPONSE:

The legend for Figure 8 in the Structural and Property Modeling section of Appendix 2B, which was submitted with the Application Narrative Version 3 (submitted to GSDT on December 21, 2023), was mislabeled. The "spikes" are associated with the upscaled well logs, not the log-based porosity calculations. The spikes can be attributed to the lack of samples represented in the histogram. Overall, there were 11 upscaled well logs used in the porosity

model. Both the U Shale and Lower Santos Shale are represented by two layers each in the geocellular model. For both intervals there are 22 upscaled log samples, limiting the histogram distributions and resulting in spikes. In comparison, the U and W Sandstones have over 5 layers each in the geocellular model, resulting in a smoother distribution of upscaled samples. The geocellular model and log derived porosity curves have abundant samples and provide a good data match for all zones within the model.

The legend of Figure 8 has been updated to match the lines shown in the images. Text has been added to Appendix 2B (Structural and Property Modeling) of the Application Narrative Version 4 (to be submitted to the GSDT) to address the spikes in the upscaled porosity logs within the Lower Santos Shale and U Shale histograms shown in Figure 8.

7. **From USDOE's Carbon Storage Atlas (USDOE, 2015), "The methodology employed in Atlas V is based on volumetric methods for estimating subsurface volumes. Subsurface storage volumes depend on geologic properties and storage efficiency."**
   a. **Please clarify whether storage efficiency was included in Aera's methodology (and if Monte Carlo methods or other methods were used to determine the storage efficiency).**

Aera's Response:
Storage efficiency was not utilized in the storage calculation methodology presented in the Application Narrative Version 2 (submitted to GSDT on March 10, 2023) since the sequestration zone is a depleted oil and gas reservoir. The sequestered CO_2 is modeled to primarily occupy the original free gas cap of the oil and gas reservoir. Consequently, the primary factor in estimating storage capacity was the pore volume of the withdrawn gas and fluids from the reservoir and not the storage efficiency of the water leg. No Monte Carlo methods were used.

Text has been added to Section 2.4.4.2 of the Application Narrative Version 3 (to be submitted to the GSDT separately) in response to this comment.

Comments:
The response is satisfactory, however storage capacity estimates will need updating after additional data are collected during the construction of the injection wells and historical performance data are obtained.

RESPONSE:

Acknowledged. Aera will update storage capacity estimates with the data collected during well construction and pre-operational testing. Additionally, performance data collected during project operation will be utilized to update the AoR model every five years, at minimum, as described in Attachment B Section 4, including updated assessments of storage capacity. No alterations have been made to the Application Narrative Version 4 in response to this comment.

8. **Regarding the influence of CO_2 injection location on fault stability, Aera proposes to inject CO_2 into nine dedicated injection wells (four new wells and five re-purposed existing wells). The Project, as proposed, will have the capacity to inject ~ 3.6 million**

metric (MM) tons of CO_2 /yr. and will operate for ~ 7 years sequestering a total of ~ 27 MM mt CO_2. Has Aera considered in their simulations the superposition of pressure resulting from simultaneous operation of more than one injection well, leading to a larger pressure front extent?

Aera's Response:
Aera is planning to inject simultaneously into the nine injection wells. For both the Attachment B Version 1 (submitted to GSDT on January 19, 2023) and the revised Attachment B Version 2 (to be submitted to the GSDT separately), the reservoir simulation model includes the simultaneous injection of CO_2 into the nine wells and shows that the pressure front reaches the edges of the fault-bounded compartment and defines the AoR. As discussed in question 8 above, the simulation model limits injection to less than 80% of the fracture gradient and exhibits no superposition of pressure from simultaneous injection. Based on reservoir modeling and pressure histories, the faults are defined as sealing and will contain pressure within the fault-bounded compartment.

No modifications have been made to the Application Narrative Version 3 (to be submitted to the GSDT separately) in response to this comment.

Comments:
It is important to consider the maximum increase in pore pressure during injection and post injection in addition to limiting the injection pressure below 80% of the fracture gradient of the injection zone.

Questions/Requests:
- *Provide the distance from each of the nine injection wells to the nearest faults within the AoR and AoI.*

RESPONSE:

In response to the request to provide the distance from each of the nine injection wells to the nearest faults within the AoR and AoI, Aera has added Table 2.3-2 – Distance from Injection Wells to Faults within the AoI to the Application Narrative Version 4 (to be submitted to the GSDT). References to the table have been added to Sections 2.3.3.2 and 7.1 of the Application Narrative Version 4. Results from the fault stability analysis presented in Section 2.3.3.2 of the Application Narrative include the effects of injection well-to-fault proximity.

- *Please explain/describe what testing will be done during the construction of the injection wells to confirm the reservoir modeling and pressure history data that the faults are sealing.*

RESPONSE:

As described in Section 4 of Attachment D, pressure tests will be performed on each injection well to confirm the current reservoir pressures in the 64 zone sandstones. A comparison of the reservoir pressure gradients in each of the new wells will be used to confirm pressure

connectivity within the fault-bounded AoR. Additionally, reservoir pressures and derived gradients from injection wells will be compared to data across the major bounding faults and used confirm that the faults are sealing. The newly gathered pressure data will be incorporated into the simulation model if there is deviation from existing data or interpretations.

- *Section 2.4.4.2 notes a mid-range storage capacity estimate of 32.7 MM mt of CO2 using an average of low and high range estimates. Table 7.1 and the response to Question 37 in your December 6, 2023 letter provide a proposed total CO2 mass of 31.7 MM mt using the 9 wells over 9.5 years. Are these intended to be the same value, or do these two numbers have different meanings?*

RESPONSE:

The noted discrepancy in the reported total CO_2 storage capacity is a result of comparing an initial estimate submitted with the original application to the current estimate. The initial estimate was based on material balance methods and the mid-range value was 32.7 MM mt. The more recent estimate, however, is derived from the current AoR model using a simulation that incorporates a maximum injection pressure of 80% of the frac gradient. This more robust calculation results in a storage capacity of 31.7 MM mt. The 31.7 MM mt value supersedes the original estimate of 32.7 MM mt.

9. **The Narrative document states on page 53 that "Moderate to strong ground shaking may not pose an inherent threat to CO_2 containment capacity, unless it is accompanied by fault slip within the storage."**
   a. **Clarify what elements of containment are being referred to (confining zone integrity, maintaining fault sealing properties, well integrity both at surface and at depth, etc.).**

Aera's Response:
"Containment capacity" in the context of the quoted statement is intended to encompass confining zone integrity, fault sealing properties, and well integrity at the surface and at depth.

In response to this comment, the statement in Section 2.6 of the Application Narrative Version 3 has been updated to read as follows:

"Moderate to strong ground shaking may not pose an inherent threat to CO_2 containment capacity (including confining zone integrity, fault sealing properties, and well integrity at the surface or at depth), unless it is accompanied by fault slip within the storage complex."

Comments:
The response is generally satisfactory. While ground shaking may not automatically pose a threat to all aspects of confinement, assessing well integrity in the event of a moderate to strong seismic event is necessary to confirm that no damage is done to the well.

RESPONSE:

Acknowledged. Parameters for assessing the impact of seismic events and corresponding

responses, including mechanical integrity testing, are discussed in the Emergency and Remedial Response Plan (Attachment I) submitted to GSDT on January 19, 2023. No alterations have been made to the Application Narrative Version 4 in response to this comment.

b. Are there any analyses, literature, or examples from other projects to support your discussion regarding the ability of an injection project to withstand moderate to strong seismicity?

Aera's Response:

Evaluating the effects of seismic shaking on the integrity of oil and gas reservoirs and underground storage projects is an area of active and evolving research. Studies of existing wells in seismically active regions have attempted to quantify the risk of well bore leakage due to ground shaking (Kim, et al., 2023)[2] or identify high-risk areas where the density of existing wells and probability of strong ground motions are greatest (Kang, et al., 2019),[3] but few specific examples of well bore leakage resulting from seismic activity have been identified (Kang, et al., 2019; Iyer, et al., 2022).[4]

Similarly, while there is evidence that the permeability of active fault zones may be temporarily increased following large slip events, at least in crystalline bedrock terranes (e.g., the 1995 magnitude 7.3 Hyogoken-Nanbu earthquake on the Nojima Fault near Kobe, Japan; Kitagawa, et al., 2022),[5] studies documenting similar effects resulting from seismic shaking without induced slip were not identified. Furthermore, studies of induced seismicity associated with CO_2 injection indicate that fault leakage is unlikely to result from such events due to the high clay content of caprock formations (Vilarrasa and Carrera, 2015)[6] and is especially unlikely in thick multi-caprock systems (Rinaldi, et al., 2014).[7]

Text has been added to Section 2.6 of the Application Narrative Version 3 in response to this comment with new references from Kim et al., 2023; Kang et al., 2019; Iyer et al., 2022; Kitagawa et al., 2022; Vilarrasa and Carrera, 2015; and Rinaldi et al., 2014.

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[2] Kim, T.W., Kohli, A., Li, Y., and A.R. Kovseck, 2023, "Wellbore Leakage and Seismic Risk Assessments for Geological Carbon Dioxide Storage in Saline Formations in Kern County, California," paper presented at the *SPE Western Regional Meeting*, Anchorage, Alaska, USA, May 2023.

[3] Kang, M., Dong, Y., Yajing Liu, Y., Williams, J.P., Douglas, P.M.J., and J.M. McKenzie, 2019, "Potential increase in oil and gas well leakage due to earthquakes," *Environmental Research Communications,* v. 1, 121004.

[4] Iyer, J., Lackey, G., Edvardsen, L., Bean, A., Carroll, S.A., Huerta, N., Smith, M.M., Torsæter, M., Dilmore, R.M., and P. Cerasi, 2022, "A Review of Well Integrity Based on Field Experience at Carbon Utilization and Storage Sites," *International Journal of Greenhouse Gas Control*, vol. 113, 103533.

[5] Kitagawa, Y., Fujimori, K., and N. Koizumi, 2022, "Temporal change in permeability of the rock estimated from repeated water injection experiments near the Nojima fault in Awaji Island, Japan." *Geophysical Research Letters* 29 (10): 121-1–121- 4.

[6] Vilarrasa, V. and J. Carrera, 2015, "Geologic carbon storage is unlikely to trigger large earthquakes and reactivate faults through which CO2 could leak." *PNAS,* 112 (19): pp. 5938–5943.

[7] Rinaldi, A.P., Jeanne, P., Rutqvist, J., Cappa, F., and Y. Guglielmi, 2014, "Effects of fault-zone architecture on earthquake magnitude and gas leakage related to CO2 injection in a multi-layered sedimentary system," *Greenhouse Gases Science and Technology* 4 (1): 99–120.

Comments:
The applicant's response is generally satisfactory. While available data on the relationship between well bore leakage of CO_2 and seismic events is still limited, the applicant has provided a comprehensive list of available sources, which generally agree that very specific, anomalous circumstances are required for wellbore leakage events. These events are difficult to attribute solely to seismic events and often require failure/deficiencies in other factors including material degradation, human intervention, process disturbance, inherent design errors, and/or other external events. In addition, the lithologic layers of the project site consist of a heterogeneous mixture of interwoven claystone layers, which, according to the provided sources, would reduce the risk of CO_2 leaks along preexisting faults during seismic events.

RESPONSE:

Acknowledged. No alterations have been made to the Application Narrative Version 4 in response to this comment.

10. Were any sensitivity analyses done for formation water chemistry to bracket the higher and lower values for key constituents such as calcium, sodium, chloride, alkalinity, etc.? If not, is this being considered for future efforts as significant variability in salinity could affect CO_2 solubility?

Aera's Response:
No sensitivity analyses were completed to assess the range of constituent concentrations observed in formation water samples. While variability within the reported concentrations would alter model results, an aggregate composition approach was selected due to the general geochemical similarity of the six samples with regards to hydrogeochemical facies and classification as brackish water. The Piper diagram provided as Figure 2.8-1 demonstrates the ubiquitous classification of the collected formation water samples as sodium-chloride dominant water types. Although absolute concentrations of key constituents do vary between samples, the relative proportion of major ions remains very similar. The concentration variability between samples is reflected in total dissolved solids (TDS) values. TDS concentrations for formation water samples range from 21,060 milligrams per liter (mg/L) to 41,000 mg/L. While this range is notable, all formation water samples can be classified as brackish water. The general geochemical consistency of formation water samples as sodium-chloride dominant brackish water guided the selection of an aggregate approach. Performing sensitivity analysis for injection zone formation water chemistry may be considered in future efforts, provided that the results of additional sample collection indicate higher variability in concentrations of major cations and anions.

Text has been added to Application Narrative Version 3 (to be submitted to the GSDT separately) Section 2.8.3.1 in response to this comment.

Comments:
Although all water samples are brackish, the applicant acknowledges that the difference between a TDS of 21,060 mg/L and a value of 41,000 mg/L is significant. While all samples are Na-Cl type waters, the large difference in TDS will affect saturation indices. TDS will also affect CO_2 solubility, with implications for solubility trapping. When pre- operational data are collected, it is

recommended to incorporate variability into the updated geochemical modeling (e.g., conduct runs with high and low concentrations) if differences of thousands of mg/L are observed.

RESPONSE:

Acknowledged. Aera will perform additional geochemical modeling runs following the results of the pre-operational testing if significant variability between samples exists. No alterations have been made to the Application Narrative Version 4 in response to this comment.

ENCLOSURE

Request for Additional Information AoR

Delineation Modeling Evaluation

Aera Energy, LLC CarbonFrontier Project

Underground Injection Control (UIC) Permit Application

Class VI Pre-Construction Permit Application No. 9UIC-CA6-FY23-1.1 to 1.0

This Computational and Static Modeling Evaluation for the proposed CarbonFrontier Class VI geologic sequestration project summarizes EPA's review of the computational modeling as described in the Area of Review and Corrective Action Plan (AoR CAP) (Attachment B Version 2, submitted December 21, 2023) of the permit application. Previous responses that require no further information are not included in this enclosure.

General Comments

The revised Attachment B does a good job of addressing EPA's comments. For example, the model domain was increased in size to properly contain the AoR calculations and history matching was revised to better fit the observations. The new sensitivity study shows that the applicants understand possible uncertainty in the model parameters. The new model sensitivity section was satisfactory, and Table 12 (pages 19-21) is a good example of how to present sensitivity results. The new material adds credibility to the application package.

Questions/Requests

1. **In Table 12 (page 19-21), it shows an increase in bounding fault transmissibility from 0 to 0.001 and 0.005 (sensitivity case numbers 1-3), which causes an increase in the average reservoir pressure at the end of injection from 4,409 psi to 4,466 psi and 4429 psi, respectively. Typically, allowing fluid to leave the domain should lead to a decrease in the average reservoir pressure. Please double check this result and provide a summary of the outcome.**

RESPONSE:

It is acknowledged that the physical phenomenon of allowing the fluid to leave the domain, which is the scenario in the sensitivity cases 2 and 3 presented in the Table 12 of Attachment B version 2, would lead to a decrease in the average reservoir pressure at the end of injection when compared to that with the base case result. However, the 64Zone reservoir is a depleted oil and gas reservoir and the sensitivity cases with varying fault transmissibility must rerun the history match prior to the prediction. Re-running the history match results in a slightly different reservoir pressure prior to injection, which is depicted in Figure 27 of Attachment B version 2. As one would expect with higher fault transmissibility than the base case, the difference in average reservoir pressure over the injection period (ΔP_{avg} from start to the end of injection) is less for case 2 and even lesser for case 3.

The discussion of sensitivity analysis methodology has been elaborated on in the revised text within Section 1.11 of Attachment B version 3 (to be submitted to the GSDT) to clarify the

points mentioned above. The observations on the average reservoir pressure changes over the injection period for the sensitivity cases 1, 2 and 3 are also discussed within the revised text of section 1.11.1 of Attachment B version 3.

a. Similarly, for both a decrease and increase in permeability (0.33x and 3x for sensitivity case numbers 7 and 8 in Table 12) there is a decrease in CO_2 plume extent and a decrease in average reservoir pressure. Please explain this non-intuitive result, or at least note this in the text of Section 1.11.4 (page 22 of the new Attachment B).

RESPONSE:

As noted in the response for question 1 above, the history match is re-run for each sensitivity case leading to a slightly different reservoir pressure prior to injection which affects the absolute plume extents and average reservoir pressures for each case. For the low permeability sensitivity scenario (case 7), the cumulative mass of CO2 injected and the difference in average reservoir pressure over the injection period (ΔP_{avg} from start to the end of injection) are lower than that for the base case scenario. This explains the reduction in the average reservoir pressure at the end of injection and a lower 100 year-plume area for case 7 when compared to that from the base case. For the case of high permeability sensitivity scenario (case 8), the cumulative mass of CO2 injected and the ΔP_{avg} over the injection period are observed to be slightly higher than the base case, thus explaining the increase in the average reservoir pressure post injection when compared to the base case. However, due to the increased porosity the 100-year plume area is seen to decrease for case 8 in comparison to the base case, though there is an increase in the cumulative injection.

The text within the section 1.11.4 of the revised Attachment B version 3 (to be submitted to the GSDT) is updated to explain the sensitivity result for cases 7 and 8 pertaining to the intrinsic permeability sensitivity parameter. The methodology of simulation for the sensitivity analysis is also explained in the revised text within Section 1.11 of Attachment B version 3.

2. For future submissions, it would be helpful to submit a 'track changes' version of the original submission to allow reviewers to more easily see how the original document was modified to address comments.

RESPONSE:

Acknowledged. We have provided tracked changes versions of the revised Attachment B version 3 and Application Narrative version 4 with the submittal of each revised document for ease of comparison.

Environmental and Experimental Botany 80 (2012) 43–53

Contents lists available at SciVerse ScienceDirect

Environmental and Experimental Botany

journal homepage: www.elsevier.com/locate/envexpbot

Potential impact of CO_2 leakage from carbon capture and storage (CCS) systems on growth and yield in spring field bean

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ARTICLE INFO

Article history:
Received 4 August 2011
Received in revised form 3 February 2012
Accepted 15 February 2012

Keywords:
Carbon capture and storage (CCS), Elevated soil CO_2, Field bean, Growth and yield, Hypoxia, *Vicia faba*

ABSTRACT

Anthropogenic carbon dioxide (CO_2) emissions are a major factor contributing to rising global temperatures and climate change. Carbon capture and storage (CCS) is a potential mitigating measure which would allow industrial emissions to be captured and stored within deep geological sites. However, in view of possible subsequent leakage to the biosphere, this study examined the impact of elevated soil CO_2 on root and shoot growth and crop yield in spring field bean (*Vicia faba* L.) under field conditions. The results revealed a strong inverse correlation between soil CO_2 and O_2 concentrations. An area containing plants exhibiting severe chlorosis, reduced growth and extensive mortality developed during the gassing period where soil [CO_2] was greatest and [O_2] was lowest. Root and shoot growth in surviving plants was significantly lower in gassed than in control plots when soil [CO_2] exceeded 10%. Mean values for vegetative (shoot, stem and leaf dry weight plant^{-1}, leaf area plant^{-1}) and reproductive variables (pod and seed number plant^{-1} and seed dry weight plant^{-1} were reduced by 36–65% compared to control plants. The only variable which was positively affected by gassing was individual seed dry weight, which was increased by 18%. The results demonstrate the severity of damage to terrestrial vegetation that may be induced by CO_2 leakage from CCS transport or storage facilities.

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1. Introduction

The increasing atmospheric concentration of greenhouse gases, particularly CO_2, has resulted in progressive warming of the Earth's climate in a phenomenon often referred to as global climate change. Atmospheric CO_2 concentration [CO_2] has increased at a mean rate of 1.9% yr^{-1} from 280 ppm before the industrial revolution to the current level of *c.* 387 ppm (IPCC, 2007). Carbon capture and storage (CCS) has been proposed as an effective option for reducing CO_2 emissions resulting from combustion of fossil fuels and would enable continued use of coal, oil and gas for the foreseeable future (Gough and Shackley, 2005). CCS technology can be used to capture CO_2 from major industrial sources before it is released to the atmosphere; this is then transported and injected into secure geological or oceanic reservoirs for underground storage as compressed gas or fluid. Although CCS technology has gained wider public acceptance than alternative energy sources such as nuclear power, CO_2 leakage from transport pipelines or storage sites (Klusman, 2003) may migrate to the Earth's surface where it adversely affects water and soil properties and plant growth (Steven and Smith, 2010). The ability to determine the integrity of prospective transport and storage facilities, a proper understanding of the pathways through which CO_2 migrates to the Earth's surface, and assurance that leakage from storage facilities is minimal are essential for effective sequestration (Amonette and Barr, 2010). However, as CCS technology has only been recently been implemented, plant responses to CO_2 leakage from CCS facilities have not been examined in detail.

As roots are important in determining plant growth, development and yield, roots and shoots must both be examined to obtain a full understanding of plant responses to elevated soil [CO_2] (Upchurch and Ritchie, 1983). However, relatively little is known regarding the effects of elevated soil [CO_2] on root growth and development as traditional methods for studying roots are both labour-intensive and destructive. Nevertheless, several studies have examined the adverse effect of elevated soil [CO_2] on the growth of plants and their root systems at sites where substrate concentrations are high, including landfill sites where increased soil [CO_2] was shown to influence root growth in green ash (*Fraxinus lanceolata* Borkh.) and hybrid poplar (Populus spp.; Flower et al., 1981). The impact of natural CO_2 springs on root function has been also examined and inhibition of root respiration was found in several grass species at Stavešinci in Slovenia (Maček et al., 2005). Similarly, injection of CO_2 into undisturbed soil profiles substantially reduced both above- and below-ground vegetative biomass in turf composed of *Lolium perenne* L., *Festuca rubra* L. and *Poa pratensis* L. (Pierce and Sjögersten, 2009) and significantly

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doi:10.1016/j.envexpbot.2012.02.007

impaired root survival and growth in seedlings of *Vicia faba* L. under field conditions (Al-Traboulsi, 2011).

Hypoxia caused by depletion of O_2 is common in flooded or waterlogged soils and landfill sites and presents an unfavourable environment for most plant species (Drew, 1997; Parent et al., 2008) which may adversely affect their growth and productivity (Pociecha et al., 2008). Several studies have shown that a lack of sufficient O_2 to support respiration causes damage and root death in plants exposed to hypoxia (Kozlowski, 1984; Crawford, 1992; Henshaw et al., 2007; Shi et al., 2007; Horchani et al., 2009). The effect of flooding has been examined in *V. faba* major L. (Balakhnina and Bennicelli, 2010) and numerous other species including *Fraxinus pennsylvanica* (Sena Gomes and Kozlowski, 1980). Low soil [O_2] associated with hypoxic conditions induced by flooding may also reduce root permeability (Clarkson et al., 2000) and leaf area, contributing to the inhibition of photosynthesis and assimilate production during the later stages of growth (Sena Gomes and Kozlowski, 1980).

It might be intuitive to assume that roots are the first organs to be damaged by hypoxic or waterlogged conditions as they are the initial point of contact with an adverse soil environment. However, information concerning the impact of elevated soil [CO_2] and depleted [O_2] on plant growth and productivity in the absence of waterlogging, such as might be induced by leaks from CCS systems, is extremely limited. The present study simulated the impact of the altered soil gaseous environment resulting from leakage of CO_2 from CCS transport pipelines or storage sites on the growth and productivity of spring field bean (*V. faba* L.), an important crop in temperate regions. The specific objective was to test the hypothesis that elevated soil [CO_2] adversely affects root and shoot growth and crop performance due to the hypoxic conditions induced.

2. Materials and methods

2.1. Site description

The Artificial Soil Gassing and Response Detection (ASGARD) facility at the University of Nottingham Sutton Bonington Campus (52.8°N, 1.2°W) was used. ASGARD is located in a field previously under permanent pasture. The soil is a sandy loam to a depth of 60 cm, below which a 20 cm gravel layer overlies clay (Ford, 2006). ASGARD comprises 34 plots, each 2.5 m × 2.5 m in area, with 50 cm wide grass paths between them; eight plots were used in this study. CO_2 (British Oxygen Company, Windleham, UK) was injected into the soil at a rate of 1 L min^{-1} through diffusers located 60 cm below the centre of four gassed plots to produce a gradient of soil [CO_2]; this was greatest close to the injector and decreased towards the edges. The remaining four plots were ungassed control plots. Computer software (TVC, Great Yarmouth, UK) controlled and recorded gas temperature, pressure and flow rate to each gassed plot. Grazing animals were excluded by an electric fence. The injection system was installed in 2006, two years before the experiment began.

2.2. Gas measurements

Two permanent plastic sampling tubes (100 cm deep × 19 mm internal diameter) were installed vertically to a depth of 30 cm at distances of 15 and 70 cm from the centre of each gassed plot (Fig. 1a). These were sealed at the bottom but holes near their lower end allowed gas exchange to maintain equilibrium with the surrounding soil atmosphere. A valve at the top of each sampling tube allowed soil [CO_2] and [O_2] to be measured using a GA2000 Landfill Gas Analyser (Geotechnical Instruments, Warwickshire, UK).

Barholing measurements were used to map the underground dispersion of CO_2 and O_2. All plots were nominally sub-divided into

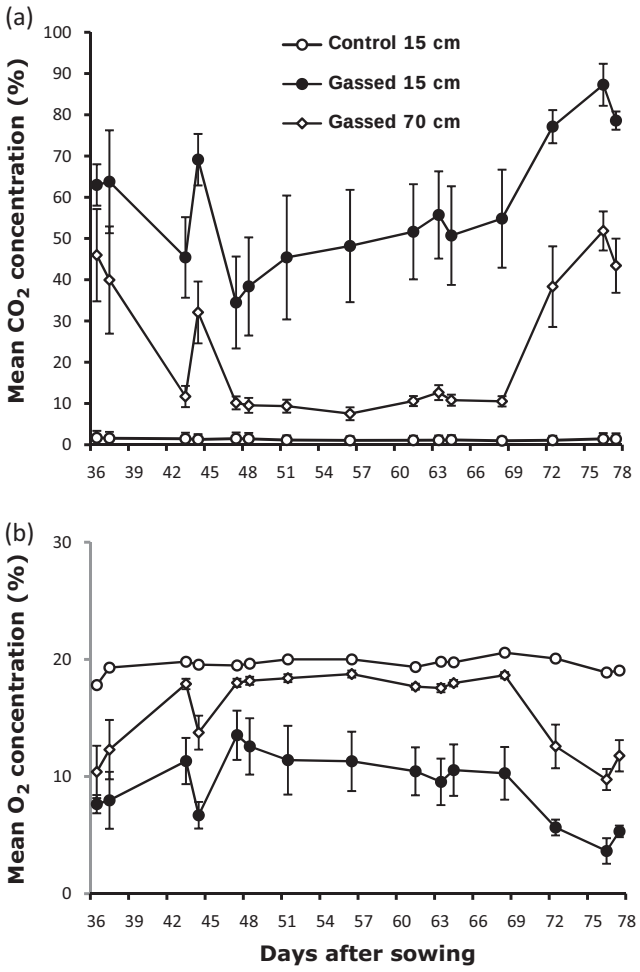


Fig. 1. Mean CO_2 (a) and O_2 concentrations (b) in control and gassed plots measured 15 or 70 cm from the plot centre between 10 July and 20 August 2008 (36-77 DAS). Double standard errors of the mean are shown ($n = 4$).

25 squares, each 50 cm × 50 cm in area, and a purpose-designed barhole device (Peter Wood & Co Ltd, Sheffield, UK) was inserted to a depth of 30 cm at each corner of all squares. The GA2000 probe was inserted into the hole immediately after removing the barholing device to measure [CO_2] and [O_2]. The maximum [CO_2] value displayed over a 40 s sampling period was recorded as the concentration for that location and [CO_2] values for all corners of each square were used to calculate the mean value. The mean values for each square in the four replicate gassed plots were displayed as contour maps using a grid-based graphics program, Surfer 07 (Golden Software Inc., Golden, Co, USA). Measurements at ASGARD in 2006 revealed a strong negative linear correlation between soil [CO_2] and [O_2] ($R^2 = 0.96$; Steven and Smith, 2010) whereby:

$$[O_2] = 20.078 - 0.2147[CO_2] \quad (1)$$

where [] denotes percentage gas concentration. This equation was used to estimate [O_2] from the corresponding [CO_2] values to construct [O_2] contour maps.

2.3. Minirhizotron technology

Root distribution was examined using a minirhizotron system (Bartz Technology Inc., Santa Barbara, CA, USA). On 1 May 2008, two transparent tubes (125 cm long × 5 cm diameter) were installed at an angle of 45° to the soil surface to a vertical depth of 70 cm in each gassed plot; one tube was installed in each control plot. Tubes

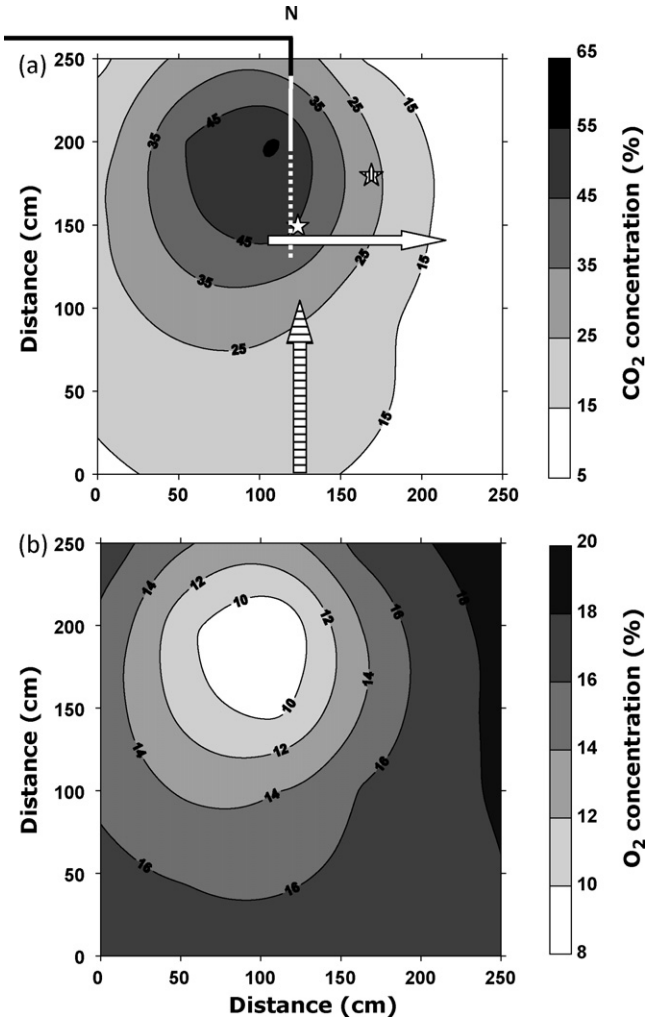


Fig. 2. Contour maps showing mean distribution of (a) CO_2 and (b) O_2 concentrations at 30 cm depth in the gassed plots. *X* and *Y* axes represent plot area (2.5 m × 2.5 m; $n = 4$). In (a) the horizontal black line and solid and dashed white line entering the plot from the North (N) represent the CO_2 supply line. The white and stippled stars represent the sampling points 15 and 70 cm from the plot centre; horizontal white and vertical stippled arrows represent orientations of the Bartz minirhizotron tubes.

in the gassed plots were inserted in different orientations i.e. tube G_A entered the soil 100 cm from the plot centre, where soil [CO_2] was low, and sloped perpendicularly downwards across plant rows towards the plot centre (Fig. 2a). Tube G_B entered the soil 15 cm from the plot centre, where soil [CO_2] was greatest, between two plant rows, and sloped parallel to the plant rows, towards the edge of the plot. Tube G_A allowed the shallow roots of the potentially least damaged plants and the deeper roots of the most damaged plants near the plot centre to be examined. Conversely, tube G_B examined the shallow roots of the most damaged plants near the plot centre and the deeper roots of the least damaged plants near the plot margins.

A BTC-2 microvideo camera system (Bartz Technology Inc., Santa Barbara, CA, USA) was used to record images of roots growing against the outer surface of the access tubes. The BTC I-CAP Image Capture System, a software and hardware package for digitising images, was used to collect and process root images. Images (12.5 mm vertical × 18 mm horizontal, area 2.43 cm^2) were recorded at 1 cm vertical depth intervals in each tube on seven sampling dates between July and August 2008. A total of 63 frames representing soil depths between 0 and 63 cm were analysed for each tube and sampling date, giving a total of 5292 images (63 depths × 12 tubes × 7 dates). The images were grouped within the depth ranges 0–10, 10–20, 20–30, 30–40, 40–50, 50–60 and 60–70 cm and analysed using RooTracker Version 2.0.3, a software package for root image analysis (Dave Tremmel, Duke University, Durham, NC, USA). The number of live main and lateral roots, root length and root diameter within each category were determined for each image.

2.4. Plant material and measurements

A dwarf field bean variety (*V. faba* L. *cv*. The Sutton; Thompson and Morgan Seeds, Suffolk, UK) was chosen to match the planned early summer sowing date, avoid lodging and facilitate measurements of root and shoot growth. This variety can be sown between March and July under field conditions in the UK and, although only 30 cm tall, produces numerous pods. As a short season crop which reaches maturity in 10–12 weeks, it was ideally suited for the present study. All plots were cultivated manually before hand-sowing seeds on 4 June 2008 at a depth of 5 cm in eight rows per plot. Spacing was 30 cm between rows and 23 cm within rows, giving a population of 80 plants $plot^{-1}$.

CO_2 injection began on 4 July 2008, 31 days after sowing (DAS), to allow the plants to establish fully prior to exposure as previous studies of winter-sown field bean showed that exposure to elevated soil [CO_2] from the time of sowing prevented germination and seedling establishment in the centre of gassed plots where [CO_2] was highest (Al-Traboulsi, 2011). Soil [CO_2] and [O_2] at a depth of 30 cm were measured daily 15 cm from the centre of the control plots and 15 and 70 cm from the centre of the gassed plots (Fig. 1a) between 10 July and 20 August 2008 (36-77 DAS). Chlorophyll content, plant height and leaf and pod number $plant^{-1}$ were determined non-destructively during the injection period for 10 randomly selected plants located 30, 60, 90 and 120 cm from the centre of each plot. The chlorophyll content of healthy leaves from the top, middle and bottom of each plant was determined using a portable chlorophyll meter (SPAD 502, Minolta, Chicago, USA); five SPAD readings for each leaf were averaged to provide mean values.

At harvest on 21 August 2008 (77 DAS), the gassed plots were sub-divided into 25 squares, each 50 cm × 50 cm in area, before recording plant number and harvesting plants from all squares. Six 50 cm × 50 cm squares were randomly selected for destructive harvest in each control plot. Height to the tip of the main stem was measured using a ruler and pod number was counted for all plants in each square. The plants were then divided into leaves, stems and pods; seed number pod^{-1} and seed number $plant^{-1}$ were counted. Sub-samples (*c*. 20%) of leaves and stems from each square were weighed to determine fresh weight and leaf area was measured using a leaf area meter (Li-Cor Model 3100, Lincoln, NE, USA). All sub-samples were oven-dried at 85 °C for 48 h before determining dry weight. Mean monthly values for air temperature and relative humidity and total monthly rainfall and irradiance during the experimental period and the preceding 10 year period (1997–2007) were obtained from the Sutton Bonington meteorological centre.

2.5. Statistical analysis

The effects of treatment and location within the gassed plots on plant height, leaf and pod number $plant^{-1}$ and SPAD values were tested using repeated measures ANOVA. CO_2 treatment was the main effect (independent factor) with two levels, gassed and control; plant location (10, 30, 60, 90 and 120 cm from plot centre) and date were analysed as repeated measures. Interaction effects were also tested i.e. CO_2 × location, CO_2 × date, date × location, CO_2 × date × location. Effects of CO_2 enrichment and depth in the soil profile on root number, length and diameter were tested

Table 1
Mean daily air temperature, relative humidity, total rainfall and cumulative irradiance during the experimental period in 2008 and mean values for the preceding 10 year period (1997-2007). Standard errors of the mean are shown for mean values.

	Mean air temperature (°C)		Relative humidity (%)		Total rainfall (mm)		Total irradiance (MJ m^{-2})	
Month	1997/2007	2008	1997/2007	2008	1997/2007	2008	1997/2007	2008
June	15.2 ± 0.2	14.2 ± 0.3	79.0 ± 1.5	80.3 ± 1.5	56.3 ± 12.9	39.6	530 ± 10.4	564.2
July	16.6 ± 0.5	16.4 ± 0.4	80.1 ± 1.5	81.1 ± 1.4	57.6 ± 5.6	63.0	513 ± 21.6	527.0
August	16.7 ± 0.1	16.7 ± 0.2	80.5 ± 1.6	81.7 ± 1.3	63.2 ± 23.9	71.8	446 ± 8.1	391.9

using repeated measures ANOVA with [CO_2] as the main effect (independent factor) with two levels; the influence of depth (7 depths) and date (7 dates) were analysed as repeated measures. Interaction effects for CO_2 × depth, CO_2 × date, date × depth and CO_2 × date × depth were tested. One-way ANOVA was used to analyse leaf, stem and root fresh and dry weights, leaf area, pod number plant^{-1} and seed number plant^{-1} at harvest, with CO_2 as the main factor with two levels, control and gassed. All analyses were performed using SPSS 16.0 and significance was accepted at $P \leq 0.05$. Mean values for growth variables determined at harvest for all plants present within the 25 sub-plots in the gassed plots were displayed on contour maps using Surfer 07 (Golden Software, Inc., Colorado, USA). The correlations between shoot dry weight (g plant^{-1}) and soil [CO_2] and [O_2] were tested for significance and linear relationships fitted.

3. Results

3.1. Climatic conditions

Mean air temperature and relative humidity and monthly rainfall and irradiance during the experimental period were generally comparable to the corresponding values for the preceding 10 year period, although rainfall in June and August 2008 was respectively below and above the long-term average (Table 1). The differences in monthly rainfall were reflected by the above- and below-average cumulative irradiances in June and August.

3.2. Soil CO_2 and O_2 concentrations

Soil [CO_2] 15 cm from the centre of the gassed plots was much greater than at 70 cm from the centre ($P < 0.05$; Fig. 1a), and values for both locations were greater than in the control plots ($P < 0.05$). The increased [CO_2] in the gassed plots was reflected by a sharp decline in soil [O_2] relative to control plots (Fig. 1b), particularly near the plot centre. Mean soil [CO_2] was greatest near the injection point (56%; Fig. 2a), while [O_2] was at its lowest (5%; Fig. 2b). [CO_2] decreased towards the edges of the gassed plots, where a seasonal mean of 8.3% was recorded; seasonal mean [O_2] increased to 19.7% near the edges of the gassed plots, identical to the value for control plots (19.6%).

3.3. Growth parameters and chlorophyll content

The leaves of plants located near the CO_2 injection point became chlorotic 11 days after injection began (42 DAS), and this was followed by premature senescence, leaf abscission and plant death. An area of visible injury 100–120 cm in diameter developed close to the injection point, where [CO_2] ranged from 20 to 60% and [O_2] from 8 to 16%. Seeds and seedlings at the centre of this impact zone were killed, whereas seedlings further from the plot centre were chlorotic and stunted but survived. This effect intensified with time as plants near the injection point which experienced soil [CO_2] of 45–60% died before the experiment ended. The number of surviving plants 10 and 30 cm from the centre of gassed plots decreased by *c.* 50% between 43 and 48 DAS compared to distances of 90 and 120 cm from the centre and in the control treatment; the decrease in survival 60 cm from the centre of gassed plots was smaller (12.5%). At 69 DAS, survival 10, 30 and 60 cm from the plot centre was respectively 25, 50 and 75% compared to greater distances in the gassed plots and the control plots, in which no mortality occurred.

The CO_2 × date, CO_2 × location and CO_2 × date × location interactions were significant for plant height and leaf number plant^{-1} (Table 2). The date × location interaction was significant for height, while the CO_2 × location interaction was significant for pod number plant^{-1}. Height increased with time in both treatments, but control plants reached a maximum of 55.1 ± 3.4 cm at 69 DAS compared to 35.3 ± 6.3 and 38.5 ± 4.9 cm at distances of 10 and 120 cm from the centre of gassed plots ($P < 0.001$). Leaf number plant^{-1} increased with time in both treatments (Fig. 3a; $P < 0.05$), but was again greater in control plants ($P < 0.05$). Surviving plants 10 cm from the centre of gassed plots had fewer leaves than those further from the centre during the later stages of the experiment; at 36 DAS, leaf number plant^{-1} 10 cm from plot centre was 10.5% greater in control plants (29 ± 2.8) than in gassed plants (26 ± 3.5), but this difference increased to 40.8% by 69 DAS. Mean pod number plant^{-1} at 54 DAS for surviving plants 10 cm from the plot centre was 4-fold greater in control plants (6.6 ± 1.4) than in gassed plants (1.5 ± 0.3; Fig. 3b), but decreased by 28% in gassed plants between 61 and 69 DAS ($P < 0.05$); no significant change in pod number plant^{-1} with

Table 2
Summary of two-way repeated measures ANOVA to determine the effect of elevated soil CO_2 on plant height, leaf number plant^{-1}, pod number plant^{-1} and SPAD values ($n = 4$ comprising 40 gassed plants and 40 control plants).

Variable	Source	*F*	*P*
Plant height (cm)	CO_2	8.7	0.025
	Date	41.2	<0.001
	Location	2.1	0.119
	CO_2 × date	7.5	0.014
	CO_2 × location	6.6	<0.001
	Date × location	5.8	<0.001
	CO_2 × date × location	6.5	<0.001
Leaf number plant^{-1}	CO_2	7.1	0.037
	Date	38.0	<0.001
	Location	1.6	0.20
	CO_2 × date	7.6	0.016
	CO_2 × location	3.5	0.02
	Date × location	2.2	0.098
	CO_2 × date × location	3.2	0.027
Pod number plant^{-1}	CO_2	3.4	0.12
	Date	38.0	0.003
	Location	0.66	0.62
	CO_2 × date	0.87	0.43
	CO_2 × location	4.34	0.009
	Date × location	0.55	0.81
	CO_2 × date × location	1.04	0.42
SPAD values	CO_2	10.1	<0.01
	Date	22.2	<0.001
	Location	5.72	0.022
	CO_2 × date	6.97	0.002
	CO_2 × location	7.71	0.009
	Date × location	3.27	<0.001
	CO_2 × date × location	4.95	<0.001

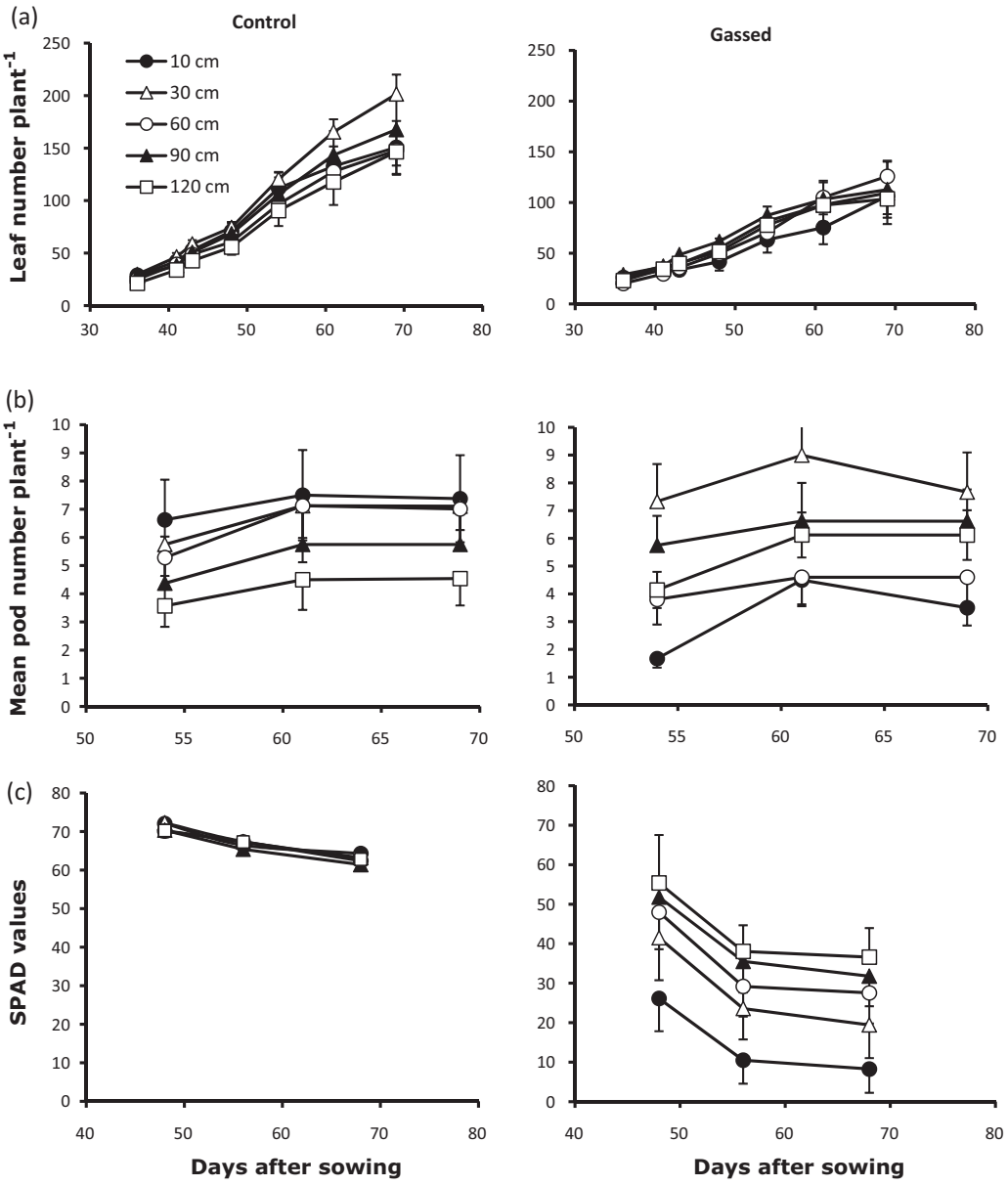


Fig. 3. (a) Leaf number plant^{-1}, (b) pod number plant^{-1} and (c) SPAD values in control and gassed plots at distances of 10, 30, 60, 90 and 120 cm from the centre. Single standard errors of the mean are shown ($n = 4$ comprising 40 gassed and 40 control plants). Note differing x-axis scales.

time was apparent at greater distances from the centre of gassed plots.

The effect of CO_2, date, location and the $CO_2 \times$ date, $CO_2 \times$ location, date $\times$ location and $CO_2 \times$ date $\times$ location interactions for chlorophyll content were all significant ($P < 0.05$; Table 2). SPAD values increased greatly with distance from the centre of gassed plots but decreased with time at all locations ($P < 0.05$; Fig. 3c). At 48 DAS, mean SPAD values for plants located 10 and 120 cm from the centre of gassed plots were respectively 26 ± 8.2 and 56 ± 12, compared to 69 ± 1.7–72 ± 1.0 in control plants. The more rapid decline in SPAD values between 56 and 68 DAS in gassed plants indicates that chlorophyll degradation was accelerated.

3.4. Growth variables at harvest

Mean values for all growth variables except individual seed weight were greatly reduced in gassed plants at harvest (Table 3). Leaf and stem dry weight and leaf area plant^{-1} were respectively 64% ($P < 0.001$), 53% ($P < 0.001$) and 65% ($P < 0.001$) lower in gassed plants than in control plants. Exposure to elevated soil CO_2 also reduced pod and seed number plant^{-1} by 42 and 46% respectively ($P < 0.001$), but the effect on seed number pod^{-1} was much smaller (11%). Individual seed weight was increased by 13.5% relative to control plants but this was insufficient to prevent a 36% reduction in seed weight plant^{-1} due to the greatly reduced pod number plant^{-1}.

Fig. 4 illustrates the substantial spatial variation in leaf area and leaf, seed and shoot dry weight plant^{-1} at harvest in the gassed plots. As shown by the non-destructive growth measurements for the same plants, values for all variables were greatest near the edges of the gassed plots and decreased sharply towards the injection point. The pattern of growth in the gassed plots reflected that for gas dispersion (Fig. 2) as plants exposed to lower [CO_2] than experienced at the plot centre survived, but showed more severe growth reductions than plants furthest from the injection point or in the

Table 3
Growth characteristics at harvest (mean ± SEM) for plants grown in control and CO_2-enriched soils ($n = 4$ comprising 400 gassed and 100 control plants). Percentage changes in vegetative and reproductive variables in gassed relative to control plants are shown; ↓ and ↑ denote increases and decreases.

Parameter	Control	Gassed	*F*	*P*	(Change %)
Shoot dry weight (g plant^{-1})	29.2 ± 1.03	14.8 ± 0.9	102.7	<0.001	49.3↓
Stem dry weight (g plant^{-1})	9.05 ± 0.5	4.28 ± 0.2	60.7	<0.001	52.7↓
Leaf dry weight (g plant^{-1})	6.95 ± 0.4	2.54 ± 0.2	90.8	<0.001	63.5↓
Leaf area (cm^2 plant^{-1})	1224 ± 72.4	430 ± 37.3	65.5	<0.001	64.9↓
Pod number plant^{-1}	6.7 ± 0.4	3.9 ± 0.26	32.4	<0.001	41.8↓
Seed number pod^{-1}	3.04 ± 0.07	2.7 ± 0.12	4.3	<0.05	11.1↓
Seed number plant^{-1}	20.3 ± 1.2	11.0 ± 0.7	38.9	<0.001	45.8↓
Seed dry weight (g plant^{-1})	7.5 ± 0.40	4.8 ± 0.30	24.9	<0.001	36.0↓
Mean seed weight (g seed^{-1})	0.37 ± 0.01	0.42 ± 0.02	1.9	ns	13.5↑

control plots. Shoot dry weight plant^{-1} was negatively correlated with [CO_2] ($P < 0.001$) and positively correlated with [O_2] ($P < 0.001$; Fig. 5); similar correlations were apparent for all growth variables examined.

3.5. Root growth

The effects of [CO_2] and soil depth on root number, length and diameter were significant ($P < 0.05$ to <0.001; Table 4), as was the $CO_2 \times$ date interaction for root number and length. The $CO_2 \times$ depth $\times$ date interaction for root number and length approached significance, suggesting that the pattern of root distribution with depth differed between treatments. The gas concentration records showed that roots in the G_A orientation experienced a mean [CO_2] of 20% at 30 cm depth, whereas the corresponding value for the G_B orientation was 42% due to their proximity to the centre of the gassed plots.

Main and lateral root numbers and length (Fig. 6a AND b) increased much more rapidly with time and roots reached greater maximum depths in the control plots than for both minirhiztron orientations in the gassed treatment. At 63 and 77 DAS, main and lateral root numbers and length were greater in the 10–20 cm horizon of the control treatment and the G_A orientation in the gassed plots than for any other horizon. Main root number in the 10–20 cm horizon was respectively 68% and 87% greater in control plants than in the G_A and G_B orientations in the gassed treatment at 63 and 77 DAS. Main root number and length were consistently greater for the G_A than for the G_B orientation for all horizons and sampling dates ($P < 0.05$). The main roots penetrated to 70 cm by 77 DAS in the control plots (Fig. 6), but reached a maximum depth of only 40 cm

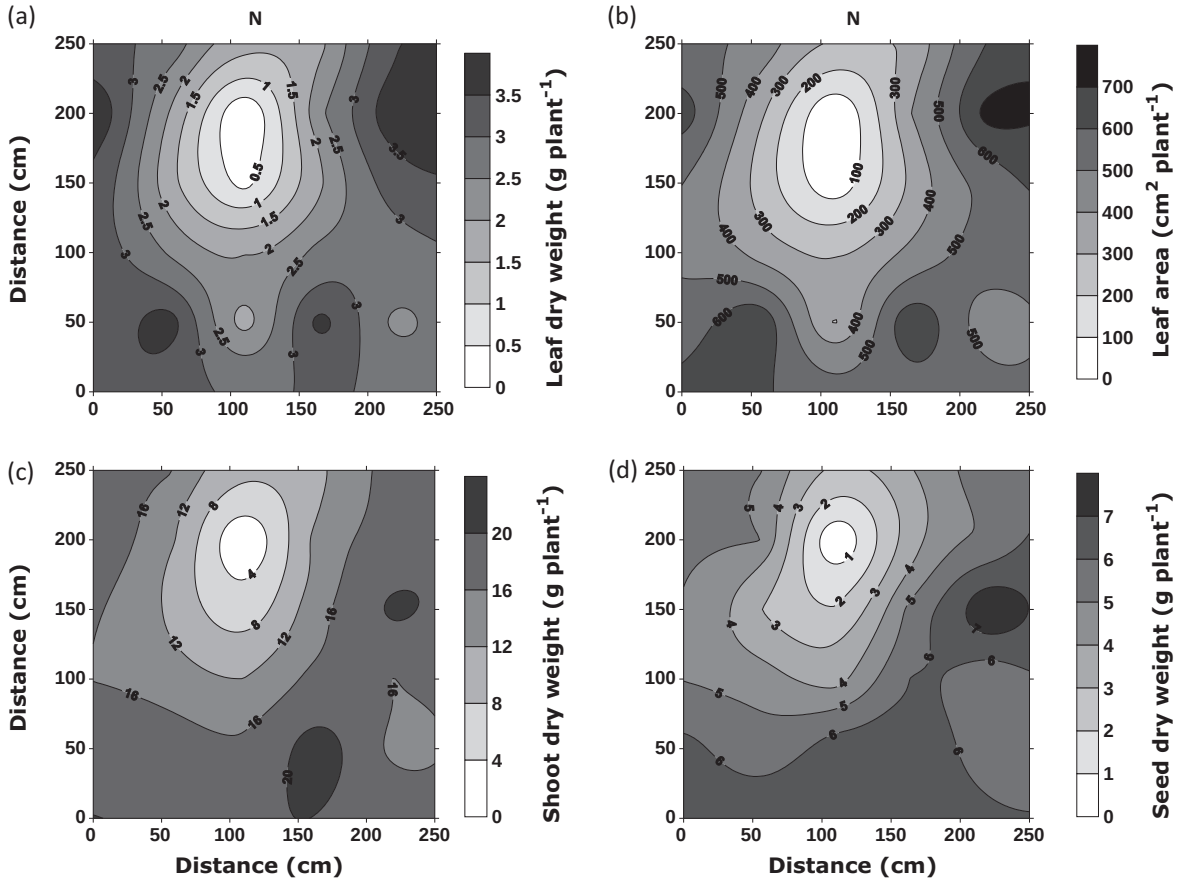


Fig. 4. Contour maps showing (a) leaf dry weight (b) leaf area, (c) shoot dry weight and (d) seed dry weight plant^{-1} in the gassed plots at harvest. *X* and *Y* axes represent plot area (2.5 m × 2.5 m). Contour values (*Z*) represent mean values ($n = 4$ comprising 400 gassed plants). *N* denotes North.

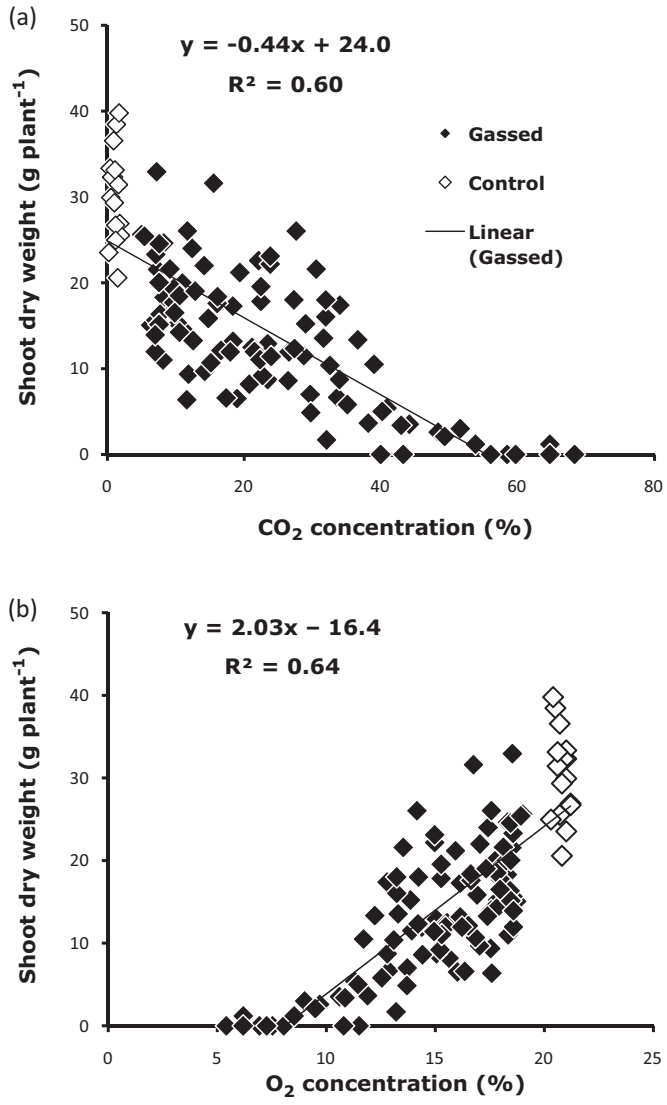


Fig. 5. Correlation between shoot dry weight at harvest and (a) mean soil CO_2 and (b) mean O_2 concentration. Regression equations are shown.

Table 4
ANOVA summary for the root characteristics of plants grown in control or CO_2-enriched soils measured at seven dates between July and August 2008 ($n = 4$).

Variable	Source	F	P
Root number	CO_2	7.34	0.013
	Date	5.38	0.019
	Location	3.13	0.049
	CO_2 × date	9.42	<0.001
	CO_2 × location	1.90	0.115
	Date × location	3.96	0.006
	CO_2 × date × location	1.90	0.077
Root length (mm)	CO_2	6.74	0.016
	Date	1.59	0.195
	Location	4.23	0.001
	CO_2 × date	20.90	<0.001
	CO_2 × location	0.88	0.550
	Date × location	1.56	0.067
	CO_2 × date × location	1.42	0.063
Root diameter (mm)	CO_2	5.60	0.026
	Date	0.55	0.651
	Location	2.20	0.072
	CO_2 × date	13.80	<0.001
	CO_2 × location	1.09	0.388
	Date × location	2.39	0.001
	CO_2 × date × location	1.12	0.304

at 63 DAS for both orientations in the gassed treatment ($P < 0.05$; Table 4). By 77 DAS, maximum rooting depth in the G_B orientation had declined to 30 cm due to the disappearance of roots in the 30–40 cm horizon, whereas roots in the G_A orientation were still present to 40 cm, although none penetrated to greater depths. Numerous lateral roots were produced in the 10–30 cm horizons of control plots, and mean lateral root numbers in the 10–20 cm horizon were respectively 2.6 ± 1.1 and 3.7 ± 2.0 at 63 and 77 DAS. By contrast, lateral root production was greatly reduced in the G_A orientation (0.2 ± 0.2 and 0.4 ± 0.2 respectively at 63 and 77 DAS, and was almost entirely suppressed in the G_B orientation (Fig. 6).

4. Discussion

4.1. Soil gaseous environment

Injection of CO_2 reduced soil $[O_2]$ to an extent related to $[CO_2]$ in the soil atmosphere (Fig. 2). $[O_2]$ was much lower throughout the gassed plots than in control plots (19.6%) and other well-aerated field soils, in which $[O_2]$ is typically *c.* 20% (Good and Patrick, 1987). The contour maps of gas dispersion (Fig. 2) suggest that CO_2 migrated isotropically from the injection point to the topsoil, with the result that $[CO_2]$ decreased towards the plot margins. The inverse correlation between soil $[CO_2]$ and $[O_2]$ suggests direct physical displacement of O_2 by injection of CO_2. Previous studies at the same site also showed a strong negative correlation between soil $[CO_2]$ and $[O_2]$ ($R^2 = 0.97$; Steven and Smith, 2010); these authors concluded that injected CO_2 displaced O_2 and no significant microbial or other effects were involved. Vodnik et al. (2006) also reported a negative correlation between $[O_2]$ and $[CO_2]$ at a site naturally enriched with CO_2 in Slovenia. However, in contrast to the conclusions of Steven and Smith (2010), hypoxia induced by elevated soil $[CO_2]$ affected the arbuscular mycorrhizal fungal communities associated with the roots of several species to an extent which depended on the severity of CO_2 exposure (Maček et al., 2011).

Interestingly, the area of highest $[CO_2]$ and lowest $[O_2]$ was displaced towards the northern edge of the gassed plots rather than being directly above the injection point (Fig. 2). We speculate that this occurred because the supply pipe sloped from the soil surface at the northern edge of the plot to the diffuser 60 cm below the plot centre. Some of the CO_2 released may have moved preferentially along the outer surface of the supply pipe rather than dispersing vertically upwards through the soil, causing the observed asymmetric gas dispersion. However, this does not invalidate the experimental objective of investigating the potential impact of CO_2 leakage from CCS systems as effects on crop performance were related the actual distribution of $[CO_2]$ and $[O_2]$ within the plots.

4.2. Shoot growth

The combination of elevated soil $[CO_2]$ and depleted $[O_2]$ greatly affected plant survival, growth and shoot biomass near the injection point, but these effects decreased with increasing distance (Figs. 3 and 4); all growth variables were negatively correlated with soil $[CO_2]$ and positively correlated with $[O_2]$ (Fig. 5). It is likely that plant mortality depended on a combination of elevated soil $[CO_2]$ and exposure duration as the proportion of dead plants increased with time in the most affected area of the gassed plots; thus, exposure to $[CO_2]$ of 25–60% was lethal, whereas concentrations of 5–25% allowed survival but greatly reduced growth relative to control plants. These findings substantiate those of Williamson (1968), who reported that soil $[CO_2]$ >6% was toxic to broad bean (*V. faba* L.). Negative correlations between plant growth and soil

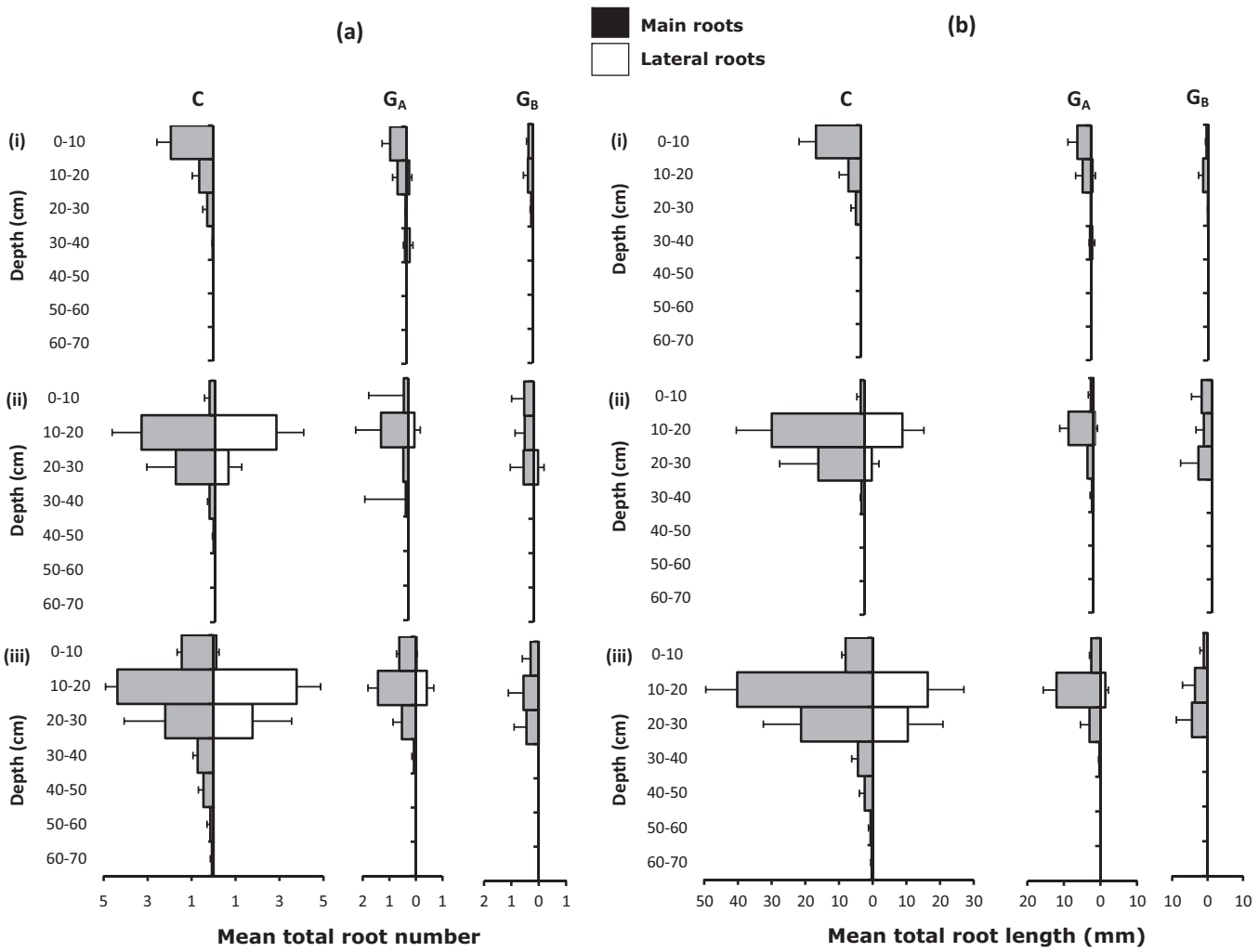


Fig. 6. (a) Main and lateral root numbers and (b) main and lateral root lengths in the control treatment (C) and G_A and G_B orientations in the gassed plots for the 0–10, 10–20, 20–30, 30–40, 40–50, 50–60 and 60–70 cm horizons at (i) 40, (ii) 63, and (iii) 77 DAS. Single standard errors of the mean are shown ($n = 4$).

$[CO_2]$ were also found when maize (*Z. mays* L.) and various native species were grown at a site naturally enriched with CO_2 in Slovenia (Vodnik et al., 2005, 2006).

Elevated soil $[CO_2]$ is likely to impact on plant survival and performance by depriving roots of O_2, whose concentration in the soil atmosphere was 16 and 8% respectively at CO_2 concentrations of 25 and 60%. This observation substantiates research at Mammoth Mountain, California, where high soil $[CO_2]$ (20–95%) resulting from seepage from beneath a volcano caused the death of trees by depriving their roots of O_2 and interfering with nutrient uptake (McGee and Gerlach, 1998; Sorey et al., 2000). As in the present study, Pociecha et al. (2008) found that 8-week-old *V. faba* plants subjected to hypoxia induced by flooding for 7 d showed substantial reductions in leaf area, stem elongation and biomass production.

The combination of high soil $[CO_2]$ and low soil $[O_2]$ induced visible foliar injury in the area of greatest $[CO_2]$ soon after gassing began. These symptoms began with yellowing of leaves caused by a rapid decline in chlorophyll content; thus, SPAD values were much lower in gassed than in control plants and declined more rapidly with time (Fig. 3c). Chlorosis occurred first in the older leaves and this was followed by premature senescence and abscission. These observations confirm evidence that reductions in chlorophyll a and b concentration in winter oilseed rape (*Brassica napus* L.) resulting from depletion of soil $[O_2]$ by flooding were greatest in the oldest leaves (Zhou and Lin, 1995). Chlorosis was also observed when pea (*Pisum sativum* L.), maize (*Z. mays* L.) (Przywara and Stepniewski, 1999) and lucerne (*Medicago falcata* L.; Smethurst and Shabala, 2003) were grown on waterlogged soil. The rapid decline in photosynthetic rate when intolerant species encounter waterlogged or hypoxic soil conditions has often been attributed to O_2 deficiency and associated reductions in stomatal conductance (Huang et al., 1997; Malik et al., 2001). It is therefore suggested that hypoxic conditions induced by CO_2 injection into the soil in the present study rapidly induced chlorosis, reduced leaf area and induced premature senescence, ultimately causing plant death in the areas of lowest soil $[O_2]$. A rapid increase in the foliar production of ethylene is a general response when plants encounter abiotic stress factors (Abeles et al., 1992), and waterlogging has previously been shown to increase internal ethylene concentrations in various crop species (Visser and Pierik, 2007; Irfan et al., 2010) including *V. faba* (El-Beltagy and Hall, 1974); it is therefore likely that the hypoxic conditions in the gassed plots promoted synthesis of this important gaseous plant growth regulator. Many of the observed responses, including progressive leaf abscission from older to younger leaves, reduced shoot growth, increased leaf senescence and abscission (Jackson and Osborne, 1970; Abeles et al., 1992; Kieber, 1997; Pell et al., 1997; Vodnik et al., 2006) are typical those associated with stress-induced increases in endogenous ethylene levels.

Although the vegetative and reproductive parameters determined at maturity (Table 3; Fig. 4) were lowest in the area of

greatest soil [CO_2], the less extreme gaseous environment near the plot margins was sufficient to reduce all growth variables relative to control plants. Comparable results were obtained when winter-sown field beans were exposed to a similar gaseous environment at the ASGARD site, as germination and seedling establishment were prevented near the CO_2 injection point; growth of the surviving seedlings again increased towards the plot margins, but was still lower than in control plants (Al-Traboulsi, 2011).

4.3. Root growth

The major impact of changes in the soil gaseous environment on root number, length and rooting depth substantiates reports that root elongation is sensitive to soil aeration and may be reduced by elevated [CO_2] and depleted soil [O_2] (Grable and Danielson, 1965; Bengough et al., 2006; Visser and Pierik, 2007). In the present study, elevated [CO_2] and reduced [O_2] suppressed lateral root production almost completely (Fig. 6). As the continued growth of lateral roots is vital to exploit the water and nutrient reserves present in previously untapped areas of soil, the sharp reduction in their production in the gassed plots is likely to have limited supplies of these essential resources, adversely affecting growth and survival.

Displacement of O_2 from CO_2-saturated soil pores in the gassed plots induced hypoxia rather than anoxia as the roots were not fully deprived of O_2 (minimum [O_2] of 8%). The impact of elevated CO_2, which was intended to be the dominant factor examined, was inextricably linked with O_2 deficiency and the consequent influence of hypoxic soil conditions. *V. faba* was clearly unable to survive the prolonged stress associated with reduced soil [O_2] during the 49 day injection period in areas of the gassed plots where [CO_2] was greatest. El-Beltagy and Hall (1974) concluded that, as a mesophyte, *V. faba* lacks the necessary anatomical, physiological and biochemical adaptations to cope with hypoxic conditions induced by waterlogging; these include the formation of aerenchyma in maize and rice (*Oryza sativum* L.) to facilitate the diffusion of oxygen from shoots to the roots (Atwell et al., 1988; He et al., 1994; Bailey-Serres and Voesenek, 2008; Perata et al., 2011). In this regard, Walter et al. (2004) reported that the leguminous species, French bean (*Phaseolus vulgaris* L.), is also highly susceptible to O_2-deficiency as no adventitious roots were produced when plants were exposed to hypoxic conditions induced by flooding. The hypoxic conditions imposed in the present study in the absence of flooding may also have increased competition between roots and soil microorganisms for O_2, to the point where this became a major limitation for root respiration and plant growth, development and yield (Jackson, 1985; Veen, 1988; Hinsinger et al., 2009).

The observed symptoms and growth effects are typical responses to hypoxia, suggesting that they resulted primarily from O_2 deficiency, with elevated [CO_2] enrichment being a secondary factor. It is unlikely that climatic conditions imposed any additional constraint on crop performance as they were comparable to the long-term means for the preceding 10 year period (Table 1). Smith et al. (2004) reported that simulated underground leaks of methane (CH_4) induced similar stress symptoms and growth responses in *V. faba*, suggesting that chlorosis and growth reductions may be generic responses to the displacement of soil O_2 by other gases; [O_2] was <10% in their study. However, in the previous study, stress symptoms developed only in seedlings with small root and shoot biomass, but not in well established plants, suggesting that the severity of the stress imposed was more extreme in the present study. It is likely that the impact of hypoxia was intensified by the additional damaging impact of high soil [CO_2], resulting in extensive mortality and severe growth and yield reductions.

4.4. Yield and yield components

The major impact of gassing on reproductive characteristics at harvest (Table 3) is unsurprising in view of the substantial effects on both root and shoot growth (Table 3; Figs. 3–6). The large reduction in seed number (46%) and dry weight plant^{-1} (36%) in gassed plants was almost entirely attributable to the 42% reduction in pod number plant^{-1}, as the impact on seed number pod^{-1} was small (11%). The only reproductive variable to show a positive response was individual seed weight, which was 13.5% greater than in control plants, although this was insufficient to maintain seed yield plant^{-1} (Table 3).

Although prolonged exposure to abiotic stress often affects reproductive development and seed yield, the nature of these effects and the ability of plants to adopt effective compensatory responses vary greatly depending on extrinsic factors, such as the timing, duration and severity of stress and climatic conditions, and intrinsic variation in the sensitivity of individual species and genotypes (Black et al., 2000, 2007, 2010, 2012). Prolonged exposure to abiotic stresses such as atmospheric pollution is known to induce effects on reproductive development and yield similar to those reported here. For example, season-long exposure of mustard (*Brassica campestris* L.) to ambient [O_3] (42–54 ppb) at Varanasi, India reduced seed number and weight plant^{-1} by 23% relative to plants grown in clean air (Singh et al., 2009). Similarly, filled grain number ear^{-1} and yield plant^{-1} were reduced when two Bangladeshi wheat varieties were exposed to 60 or 100 ppb O_3 for 7 h d^{-1} for three months (Akhtar et al., 2010), while Sarkar and Agrawal (2010) reported that ambient [O_3] at Varanasi, India decreased above-ground biomass, seed number plant^{-1} and grain yield in two Indian wheat varieties; grain yield was reduced by up to 46%. Such effects are widespread, as meta-analysis of 53 studies of wheat showed that elevated [O_3] (mean of 73 ppb) decreased grain yield by 29% compared to plants grown in clean air (Feng et al., 2008). Thus, similar effects on vegetative growth, reproductive development and yield may be induced by various stress factors in a range species, even though the initial contact point (roots or shoots) and mode of action (e.g. hypoxic soil conditions, gaseous pollutants) may differ greatly.

Stress-induced reductions in root and shoot growth in response to abiotic factors have been attributed to reductions in assimilate production or changes in partitioning (Wittig et al., 2009), perhaps resulting from callose deposition in the phloem (Matyssek et al., 2004). In support of this view, the major reductions in leaf number, leaf area and SPAD values and the extensive premature leaf senescence seen in gassed plants (Figs. 3 and 4) strongly suggest that assimilate supplies to support vegetative and reproductive growth were severely limited.

However, evidence that elevated endogenous ethylene concentrations suppress growth and induce premature senescence and abscission suggests an attractive alternative explanation (Gallie et al., 2009). Wilkinson and Davies, 2010 proposed that cross-talk between abscisic acid (ABA) and ethylene has a key role in mediating responses to various abiotic stress factors including waterlogging, which represents a milder stress than the severely depleted [O_2] and elevated [CO_2] soil atmosphere imposed in the present study. It is well documented that, when roots encounter adverse soil conditions such as compaction, ABA and 1-aminocyclopropane carboxylic acid (ACC), the precursor of ethylene, are transported through the xylem to the shoots where they induce various effects including reduced stomatal opening and growth (Roberts et al., 2002). Wilkinson and Davies (2010) suggested that any factor which increases the production or perception of ethylene is likely to block ABA-dependent responses and that increased ethylene biosynthesis is important in mediating reductions in root and shoot growth induced by abiotic stress

factors. They proposed that cross-talk between ABA and ethylene is important in regulating plant responses to abiotic stresses, perhaps mediated by interacting nitrogen-activated protein kinase (MAPK) cascades (Baier et al., 2005). Further research is needed to elucidate the role of cross-talk between these plant growth regulators in mediating plant growth and yield responses to the elevated [CO_2] and severely depleted [O_2] soil environment which may be induced by leakage of CO_2 from CCS transport and storage facilities.

5. Conclusions

The extensive plant mortality and major reductions in root and shoot growth induced by the combined effect of elevated soil [CO_2] and the consequent hypoxic conditions show that *V. faba* lacks the physiological and anatomical adaptations to cope with such conditions. The progressive decline in [CO_2] and increase in [CO_2] towards the edges of the gassed plots enabled plants to survive and perform more effectively, but growth was still greatly reduced relative to control plants. These findings suggest that CO_2 leaking from CCS facilities may reach concentrations which are lethal for unadapted plant species, and might seriously impact on root and shoot growth and function, biomass production and yield at lower concentrations. Secure geological storage of CO_2 is therefore vital. As *V. faba* has proved to be highly sensitive to elevated soil CO_2 and depleted soil [O_2], further field studies involving species better adapted to such conditions are needed to improve our understanding of the impact of leakage from CCS systems on plant survival, growth and yield.

Acknowledgements

This study was supported by the Higher Education Council for England (HEFCE) through a Strategic Research Infrastructure (SRIF) award to the University of Nottingham and a Ph.D. scholarship from the Libyan Ministry of Education. We thank Dr. Karon Smith, Matthew Tovey, John Alcock, Mark Meecham, John Corrie and Darren Hepworth for advice and technical support.

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Clarion Ledger

NEWS

Oil spills in Mississippi, Alabama lead to $3.5 million in penalties for company

Jeff Amy Associated Press

Published 9:16 a.m. CT April 30, 2019

JACKSON, Miss. — An oil company has agreed to pay federal and Mississippi regulators $3.5 million in penalties and do more to prevent oil spills under a legal settlement filed last week.

Federal and state regulators sued Denbury Resources of Plano, Texas, on Thursday, and filed a proposed consent decree at the same time. Members of the public have 30 days to comment on the settlement.

The lawsuit, filed at the behest of the U.S. Environmental Protection Agency and the Mississippi Department of Environmental Quality, documents oil spills in nine oil fields in central and southern Mississippi, plus one in Citronelle, Alabama, between 2008 and 2015. The EPA says Denbury dumped about 7,000 barrels of oil or mixtures of oil and water. The lawsuit also alleges Denbury failed to submit required facility response and spill prevention and control plans.

Denbury isn't admitting fault, but under the consent decree it would agree to enhanced reporting responsibilities as well as a "mechanical integrity program" that calls for surveying and inspecting operations and making repairs to pipelines, tanks and machinery based on how severe an oil spill threat each problem poses.

"In good faith throughout the negotiation period, we have begun implementing the program at various levels in the different fields," company spokesman John Mayer said Monday.

The federal government will get $2.4 million in civil penalties, while the Mississippi Department of Environmental Quality will get $1.1 million.

Denbury extracts oil primarily by pumping carbon dioxide underground in aging oil fields, pushing out oil that won't come out through conventional drilling. It's the largest oil producer in Mississippi.

The lawsuit counts 25 oil spills between 2008 and 2014. Many of them were only a few barrels, but a few were larger. Officials say that in summer 2013 Denbury spilled 5,000 barrels of oil and water mixture in the Tinsley field in central Mississippi's Yazoo County after a pipe shifted because of ground settlement and erosion. A number of the spills came from corrosion or rupture of pipes, and Mayer said they were cleaned up long ago.

"Most of them were completed within days of the occurrence," he said.

Andrew Whitehurst of the Gulf Restoration Network, an environmental group, said it's disappointing to see Denbury having so many problems after reworking the Mississippi fields in the early 2000s.

"The state bends over backwards to accommodate business with permits, and years later we see that the state's rivers and creeks were routinely polluted due to the company's sloppy practices and corroding pipes, tanks and collection systems," Whitehurst wrote in an email.

Denbury also paid a $662,500 fine to Mississippi regulators in 2013 after an uncontrolled carbon dioxide blowout in the Tinsley field led to suffocated wildlife and the removal of 27,000 tons of drilling mud and contaminated soil and 32,000 barrels of liquids.

The lawsuit says regulators in 2014 concluded Denbury had failed to submit required facility response and spill prevention, control and cleanup plans for a number of facilities. The consent decree says Denbury has now submitted those plans. Mayer said the missing plans have "long since" been addressed and said Denbury objected to the lawsuit mentioning them in the first place.

Carbon capture and storage (CCS)

This article is more than **1 year old**

Gas giant Chevron falls further behind on carbon capture targets for Gorgon gasfield

While scale of shortfall is uncertain, conservationists claim admission is proof the project isn't working

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target at its CCS project at the offshore Gorgon gasfield in Western Australia.

Almost all of those carbon offsets related to overseas projects to reduce emissions, with only 200,000 tonnes bought from Australia's domestic market.

The WA government has given Chevron a target to capture at least 80% of the CO2 from the gas produced at Gorgon and then inject it into a geological formation two kilometres below Barrow Island, off the state's north-west coast.

Conservationists and an energy analyst said the company's latest admission was further proof that the Gorgon project "wasn't working"."

The $3bn Gorgon project is the only operating carbon capture facility in Australia and is one of the world's largest.

The state government-set target for Gorgon to capture and store 80% of the CO2 from the gas is calculated on a five-year rolling average and in July last year Chevron said it had fallen 5.23Mt short.

Chevron was liable for capturing CO2 at its plant from July 2016, but technical problems meant injection didn't start until August 2019. Between that late start date and July 2021, 5.5Mt of CO2 was stored.

On Friday the company said the latest five-year average would see it needing to buy more offsets, but would not say how many.

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Bruce Robertson, a gas industry finance analyst at the thinktank Institute for Energy Economics and Financial Analysis, said: “The bottom line here is that the Gorgon CCS plant was enormously expensive and it doesn’t work.”

“If you’re only capturing about 50% of the CO2, that means you’re letting the rest of it go [into the atmosphere]. We’re supposed to be reducing emissions but these projects are emissions-intensive. We have our foot to the floor when we should be trying to produce less- and lower-emitting gas.”

The Guardian asked Chevron how much it had paid for the 5.23Mt.

“For commercial reasons we are not disclosing the cost or specific transaction details of the carbon credits acquired and surrendered,” a spokesperson said.

Surrendering an offset means the buyer pays for carbon credits that relate to projects that save emissions but then cancels, or “surrenders”, them instead of holding them as an asset or selling them.

According to data from the Clean Energy Regulator, between the 12 January and 2 July, Chevron surrendered 202,570 Australian carbon credit units (ACCU) - with each unit equaling one tonne of CO2 from a domestic project.

The company confirmed these related to its shortfall at Gorgon, with the rest falling under two categories of carbon offsets bought from overseas

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Bruce Robertson, LNG/Gas Analyst
Milad Mousavian, Energy Analyst
September 2022

Institute for Energy Economics and Financial Analysis
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The Carbon Capture Crux

Lessons Learned

Executive Summary

Carbon capture and storage (CCS) is a 50-year-old technology with variable results in capturing and storing carbon dioxide. Project developers have almost always reused the captured carbon for enhanced oil recovery (EOR), producing oil and gas and more emissions.

Carbon capture's role has been rejigged as a climate solution in recent years with its diverse applications being proposed to decarbonise fossil fuel plants and hard-to-abate sectors.

Some widely cited authorities are fuelling the debate on the role of this technology as a climate solution, including the International Energy Agency in both its Energy Technologies Perspectives[1] report and Net Zero by 2050 report.

This push has given a platform to polarising views on carbon capture utilisation and storage (CCUS) and carbon capture and storage (CCS): is it a greenwash to extend the life of fossil fuel assets[2] or a panacea to avert catastrophic climate change consequences?[3]

Is CCS/CCUS a greenwash to extend the life of fossil fuel assets or a panacea to avert catastrophic climate change consequences?

This report aims to shed light on the different applications and conceptualisations of CCUS/CCS, demystifying the technology's applications, concepts and categorisations. It explains the dichotomy between enhanced oil recovery and carbon capture within dedicated geological structures, and the difference between carbon capture and utilisation (CCU), CCUS and CCS. It uses a four-tiered structure to provide an overview of all carbon capture applications, which includes gas processing, power generation, industry application/production, and carbon dioxide removal technologies (CDR).

Finally, 13 flagship cases (10 in operation, two that have failed and one that has been suspended) comprising about 55% of the total nominal capture capacity

[1] IEA. Energy Technology Perspectives. September 2020.
[2] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[3] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

operating worldwide have been reviewed in detail. The projects are flagship in different senses, with each of them having unique aspects of importance.

Our sample is comprehensive, enough to learn lessons about the whole sector. IEEFA estimates that the studied cases have captured more than two-thirds of all anthropogenic carbon dioxide captured in history.

Appendix 1 summarises our case studies.

What We Found

Further extrapolated in our conclusion at the end of this report, we found:

- Failed/underperforming projects considerably outnumbered successful experiences.
- Successful CCUS exceptions mainly existed in the natural gas processing sector serving the fossil fuel industry, leading to further emissions.
- The elephant in the room of the application of CCS/CCUS in the natural gas processing sector: Scope 3 emissions are still not being accounted for.
- Captured carbon has mostly been used for enhanced oil recovery (EOR): enhancing oil production is not a climate solution.
- Using carbon capture as a greenlight to extend the life of fossil fuels power plants is a significant financial and technical risk: history confirms this.
- Some applications of CCS in industries where emissions are hard to abate (such as cement) could be studied as an interim partial solution with careful consideration.

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Section 1: Introduction to Carbon Capture and its Applications

Although carbon capture utilisation and storage (CCUS) technologies have been in use for half a century, they have gained more traction in recent years. This is especially true after widely cited energy authorities, such as the International Energy Agency (IEA), pushed them more in their portfolio of climate solutions.

The IEA's Energy Technologies Perspectives (ETP)[4] report, published in 2020, emphasises the role of CCUS and carbon capture and storage (CCS) in the clean energy transition.[5] The IEA's seminal Net Zero 2050 report, published in 2021,[6] had similar messaging. The two reports helped rejuvenate the argument for CCUS/CCS as a climate solution.

The Intergovernmental Panel on Climate Change (IPCC)'s six assessment reports provided a platform for polarising voices on CCUS/CCS, namely whether it is

[4] IEA. Energy Technology Perspectives. September 2020.
[5] IEA. CCUS in Clean Energy Transitions – Part of Energy Technology Perspectives. September 2020.
[6] IEA. Net Zero by 2050. May 2021.

greenwashing to extend the life of fossil fuel assets[7] or a panacea to avert catastrophic climate change consequences.[8] The nuance of the arguments likely depended on where interests lie, and truth on such a divisive topic is, of course, complex.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies, particularly for uninitiated stakeholders who may mistakenly think of CCUS/CCS as a single subject.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies.

CCUS/CCS is not a monolithic topic. Each CCUS/CCS application is largely running on separate tracks of maturity and cost projection. It covers various technologies and processes, contrasting environmental and social risks and opportunities, and differing mitigation potentials across multiple applications.

This report sheds light on different applications and conceptualisations of CCUS/CCS from a historical perspective and reviews most real-world flagship cases. It provides stakeholders, investors and policymakers with historical lessons from this technology. The report also tries to answer questions on whether CCUS/CCS is a climate solution in different contexts.

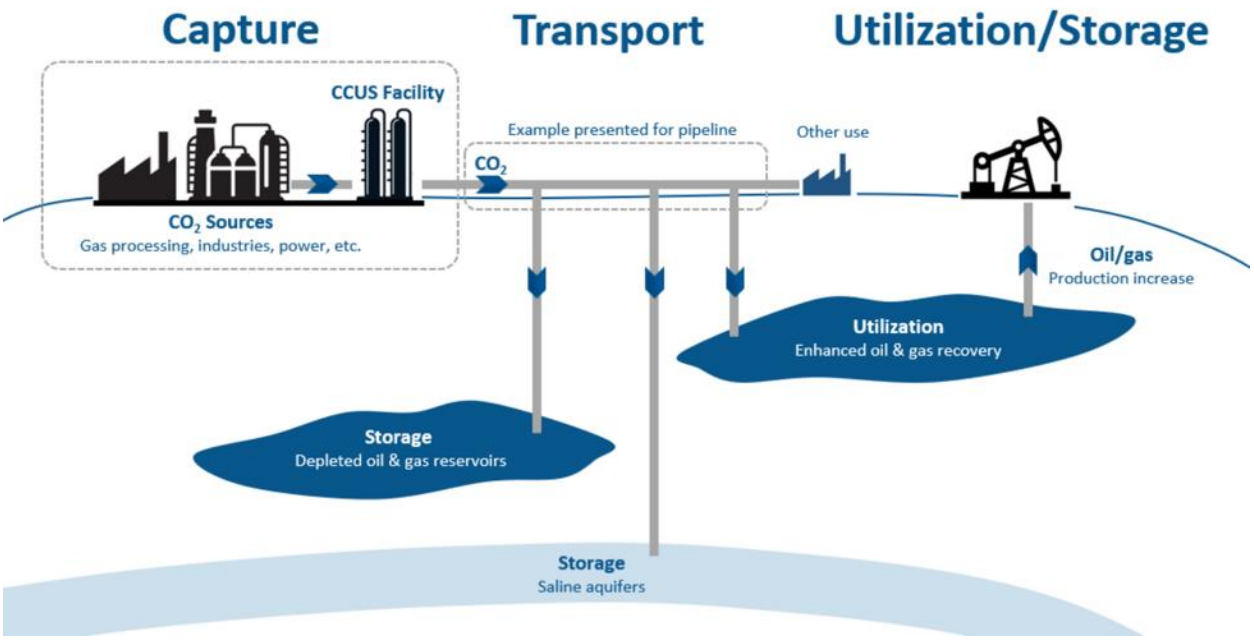
That the technology is in its infancy is not a realistic view. The climate change clock is ticking, and time is limited for trial and error. Stakeholders should take the experiences gained through half a century of utilising these technologies seriously in strategising future pathways for overcoming high emissions and climate change.

What are CCUS, CCS and CCU?

CCUS encompasses three distinct parts: capture, transport, and storage or utilisation, as depicted in Figure 1. Carbon dioxide (CO_2) captured from various stationary sources, such as chemical processes and power generation plants, is transported to sites and stored or utilised, mainly underground.

[7] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[8] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

Figure 1: CCUS Schematics



Source: IEEFA, Carbon Capture in the Southeast Asian Market Context. 2022.

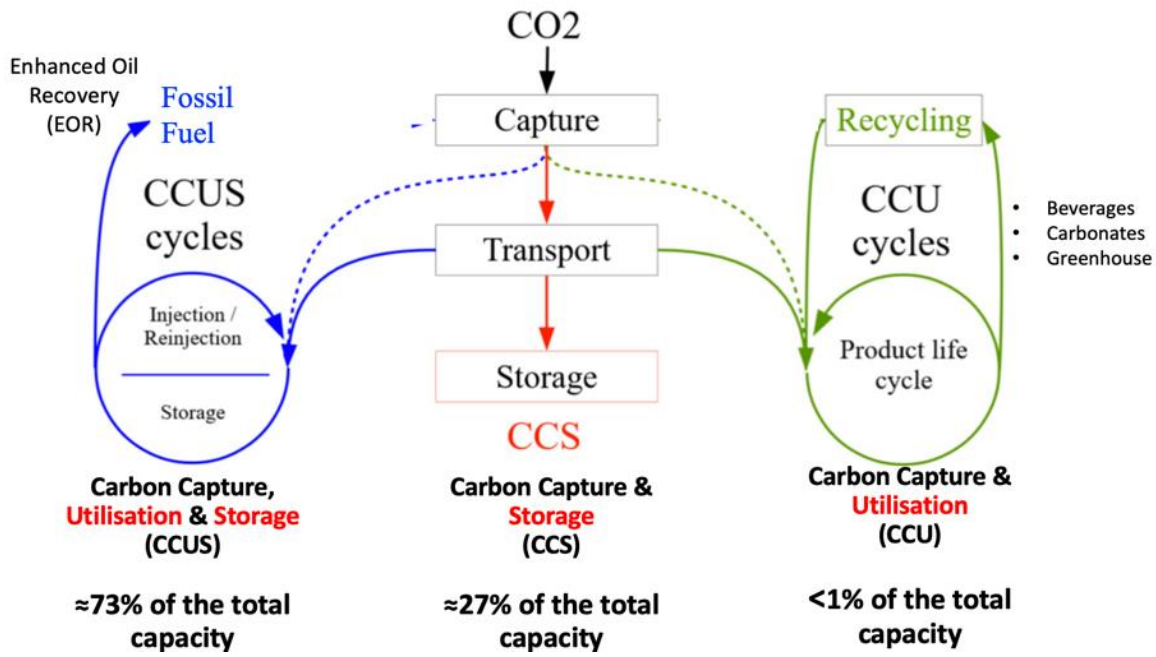
Often this CO_2 is sold as a commodity to oil and gas companies who use it to enhance their hydrocarbon production, hence the term enhanced oil recovery (EOR).[9] In this sense, carbon (C) is captured (C) and then utilised (U) by pumping it into the depleted oil and gas fields, pushing more oil and gas out of the wells and then stored (S) underground.

When CO_2 (C) is captured (C) and stored (S) underground in saline aquifers or other underground deposits and is not used for EOR, the process is called CCS.[10]

There is also a niche application of captured carbon (CC) for utilisation (U) and recycling into other valuable products, such as carbonates and beverages, and more recently products such as cement and plasterboard blocks.[11] This application is about capturing carbon and utilising it (CCU). However, compared to CCUS and CCS, the share of CCU is so far negligible (Figure 2).

[9] Global Carbon Capture Storage Institute (GCCSI). Global status of CCS 2021. 2021.
[10] From now on in this report, whenever the project is EOR, the term CCUS is used and if the project is not an EOR project and has a dedicated geological structure to store the carbon, the term CCS is used.
[11] Australian National University Reporter. Cementing the future of climate action. Winter 2021.

Figure 2: Conceptualisation of CCUS vs CCS vs CCU



Source: Sustainability Journal, MDPI, 2019.

Enhanced Oil Recovery: Injecting CO_2 to Emit CO_2

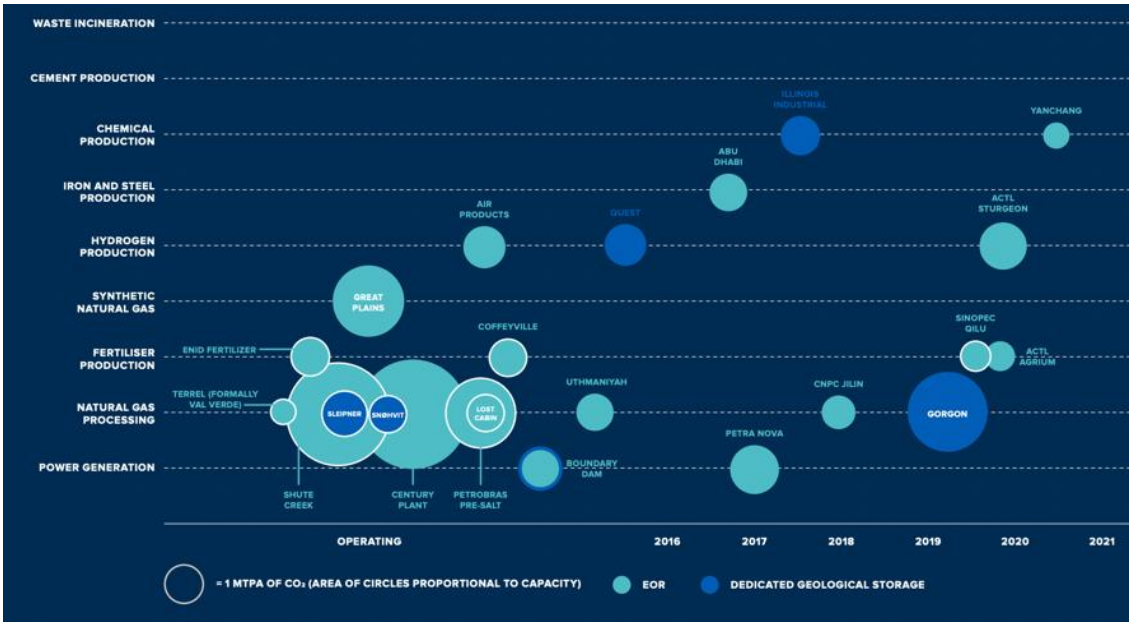
Historically, carbon capture applications have been dominated by enhanced oil recovery (EOR).

CCUS, or EOR with CO_2 (CO_2-EOR), is the largest industrial use of carbon dioxide. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons.

Today, EOR is the only industrial use of CO_2 to have reached considerable scale—EOR projects use about 73% of the CO_2 captured each year globally in recent years.[12] The figure was higher in previous decades (see Section 2). Figure 3 shows the dominance of EOR in carbon capture project applications.

[12] Global CCS Institute. Global Status of CCS 2021. 2021, p. 63.

Figure 3: Dominance of Enhanced Oil Recovery in Carbon Capture Applications



Source: Global Status of CCS Report, Global CCS Institute, 2018.

EOR enhances the oil production rate from fields that have passed the maximum output rate. Therefore, oil producers can make money by revitalising oil fields with declining production rates.

However, EOR itself leads to CO_2 emissions both directly and indirectly. The direct impact is the emissions from the fuel used to compress and pump CO_2 deep into the ground. The indirect impact is the emissions from burning the hydrocarbons that could not have come out without EOR (so-called 'Scope 3 emissions'). When a car in the street or a jet plane uses EOR-induced oil, it still emits CO_2.

In sum, CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either gets burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.[13]

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28 million tonnes (MT) out of 39MT total capture capacity, is

[13] Institute for Energy Economics and Financial Analysis (IEEFA). Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.

reinjected and sequestered in oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.[14]

According to ExxonMobil, the company has stored 120MT of CO_2, 40% of the total anthropogenic CO_2 that humans have captured.[15] Therefore, the inference is that the total cumulative captured CO_2 figure is 300MT.

Looking at the total anthropogenic carbon that humans have captured during the last 50 years demonstrates that carbon capture technology has been serving the oil industry. IEEFA has estimated that the vast majority of the total 300MT of captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Table 1: Share of CCUS vs CCS in Capturing Carbon; 50-years Cumulative and 2021[16]

Carbon Capture Type	Accumulated Captured CO_2 (Million Tonnes)	Share of Current 39MTPA Capture Capacity (%)
Enhanced Oil Recovery (EOR) - CCUS	>240 MT (80-90%)	~73%
Dedicated Geological Storage - CCS	<60 MT (10-20%)	~27%
Total	~300	100

Source: ExxonMobil, Global CCS Institute Report 2021, IEEFA, IEEFA Estimates.

[14] Several pieces of research discuss the emissions profile of CO_2-EOR systems through different lifecycle periods and boundaries. Some of them show that the CO_2-EOR could be emission-positive in some long-term situations and some discuss the CO_2-EOR as being carbon negative. Most research papers generally compare the emission profile of two types of oil: the conventionally produced oil and the CO_2-EOR-produced oil and conclude that the CO_2-EOR type produces relatively less emissions compared to the conventional one as CO_2-EOR stores some of the injected CO_2 in the ground. It is a true but misleading comparison. In fact, the emission comparison should be between a CCS plant with a dedicated geological structure to sequester CO_2 and a CO_2-EOR system (a CCS plant which serves the oil recovery where the captured CO_2 is injected into the ground to produce more oil). In this case, the CO_2-EOR system would produce more emissions considering the Scope 3 emissions when the oil is burnt plus the amount of CO_2 that comes out with the oil during the recovery process and potential fugitive emissions along the way of CO_2 transportation.

[15] ExxonMobil. Carbon Capture and Storage.

[16] For some of the projects the data on the capturing performance is not available publicly and their average designed capture capacity based on the Global CCS Institute annual reports have been used as a proxy to estimate the volume of captured carbon. Apart from the normal estimation error, the calculated figures are the best estimates based on the available data.

Demystifying Carbon Capture Applications

As opposed to being a monolithic subject, CCUS is an aggregate of technology applications across varying sectors, each sector largely running in its own development tracks and with its own drivers and maturity level. While similarities in technology may exist among different CCUS applications, they may involve different technicalities and approaches.

The four main domains for categorising carbon capture applications are:

1. Gas processing
2. Power generation
3. Industry application/production
4. Carbon dioxide removal (CDR) technologies

Gas processing has been the main CCS application globally. The extracted raw gas has a CO_2 content that needs removal to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Producing the primary usable product (i.e., natural gas) is not possible without separating CO_2. That is why the sector has used carbon capture technology for decades, not necessarily as a climate-friendly solution. On top of that, selling the captured CO_2,[17] mainly to oil producers for EOR, has enhanced the economic viability of gas development projects.

Power generation is a newer use case of CCS to decarbonise the power sector. It is known as post-combustion carbon capture as it aims to capture the CO_2 after burning the fuel. Pre- and post-combustion capture describes the stage of CO_2 capture, whether before or after burning the fuel. The strategic value lies in the ability to retrofit existing fossil-fuelled power plants with carbon capture facilities. This application has shown that it is not commercially advanced and raises several environmental concerns. As previously reported, CCS for power has also faced technical challenges in meeting performance targets. It is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.[18, 19]

CCS is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.

[17] Geological Storage of Carbon Dioxide (CO_2). 3 – Modelling the injectivity, migration and trapping of CO2 in carbon capture and storage (CCS). 2013.
[18] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[19] Ahmed Abdulla, Ryan Hanna, Kristen R Schell, Oytun Babacan and David G Victor. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. Environmental Research Letters, Volume 16, Number 1. 29 December 2020.

Industrial applications of CCS are very diverse. Companies use it to capture carbon from ethanol, methanol, fertiliser, blue hydrogen and syngas production plants. Also, its application extends to hard-to-abate industries, such as steel and cement production. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with current high commodity prices, using green hydrogen is starting to look more attractive. It is worth studying carbon capture as an interim solution in a few others.

Carbon dioxide removal (CDR) technologies—bioenergy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS)—are not well advanced technically and commercially. Theoretically, these technologies could offer environmental and social usefulness by capturing carbon from the atmosphere, thus providing the option of negative emissions, should they prove cost-competitive and commercially robust technologies. However, the operating capacity of CDR is virtually zero[20] compared to the 39 million tonnes per annum (Mtpa) CCS industry.

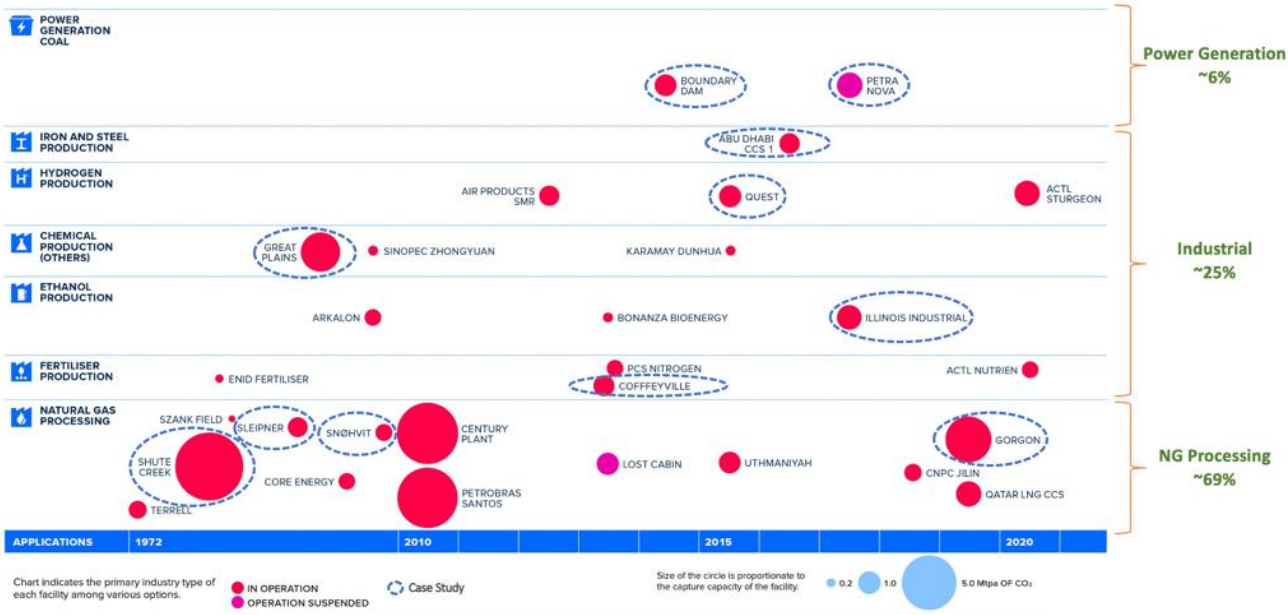
Thirteen Flagship Cases Reviewed

This report reviewed 13 operational large-scale CCS projects—including two flagship projects that failed and one that was mothballed—in terms of their history, economics and performance.[21]

As depicted in Figure 4, we fit sub-sectors identified by the Global CCS Institute into three of the four main categories of carbon capture applications. There is no category for CDR technologies in the figure as CDR is a nascent field and as noted above, the operational capacity of CDR is currently close to zero compared to the other technologies, with just one small project in Iceland.[22]

[20] For example, Orca, a direct air capture facility in Iceland that opened in September 2021, has the capacity to remove about 4000 tonnes of CO_2 a year—equivalent to the annual emissions of around 790 cars. Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.
[21] We include in our report two case studies, the Kemper Coal Gasification project and the In Salah CCS project—both of which failed—so they have not been depicted in Figure 4. Also, one of these 11 mentioned cases (Petra Nova) has been mothballed since mid-2020.
[22] Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.

Figure 4: Carbon Capture Case Studies



Source: Global CCS Institute 2021, IEEFA.

Natural gas processing dominates carbon capture projects with about 69% of total operational capacity worldwide. It is followed by industrial application, with about 25% of total capacity. Industrial applications with at least one operational CCS project include iron and steel, hydrogen, ethanol, fertiliser, and other chemical production. And a tiny proportion of about 6% is from the power generation sector. Considering the Petra Nova project shut down in 2020, the figure for power generation would be less than 3%.

In this report, we study five flagship projects in the *gas processing sector* to share the lessons from their technical performance and business processes. Four projects are operational, namely **Shute Creek** in the U.S., **Sleipner** and **Snøhvit** in Norway and **Gorgon** in Australia. The Norwegian cases are important as they have been among the few cases that could meet their designed capturing rate, mostly thanks to the unique regulatory/ business environment for Norway's oil and gas companies. Regarding their capture capacity, these four projects account for about half of the active CCS projects in the natural gas processing sector. Despite having some successful projects in this sector, several projects have underperformed their designed capture rate. We look at one such project, **In Salah** in Algeria.

Next we study three projects that have operated in the *power sector*: **Petra Nova** and **Kemper** in the U.S. and **Boundary Dam** in Canada. Petra Nova was mothballed indefinitely in 2020 and the Kemper coal gasification project failed. The report investigates the reasons. Petra Nova and Boundary Dam are the retrofits of two old coal power plants.

Finally, we have chosen five important projects to study for the *industrial applications* of carbon capture. We study these flagship cases in different sub-

sectors of the industry: the **Quest** project in the hydrogen production sub-sector; the **Great Plains CCUS** project in the chemical production sub-sector; the **Illinois Industrial CCS** project in the ethanol production sub-sector; **Coffeyville** in the fertiliser production sub-sector; and **Abu Dhabi CCUS** in hard-to-abate industries worldwide. These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications.

As this report analyses the carbon capture technology through a historical perspective and focuses on existing projects to derive lessons from failures and successes, it does not include any studies of CDR projects.

We cover all 13 flagship projects considering criteria such as their importance, availability of data, age, capacity and performance. Each project has had a unique aspect of importance, cumulatively accounting for around 55% of the total current operational capacity worldwide. Therefore, this sample is comprehensive enough to learn lessons about the whole sector.

IEEFA estimates that the studied cases have captured more than two-thirds of all 300MT of anthropogenic CO_2 in history.



Section 2. Carbon Capture Application in the Natural Gas Processing Sector

Gas processing has been the main CCS/CCUS application globally, with about 70% of current total operational capacity worldwide. Essentially for every 10 CCS/CCUS projects, seven projects are in the natural gas processing sector today.

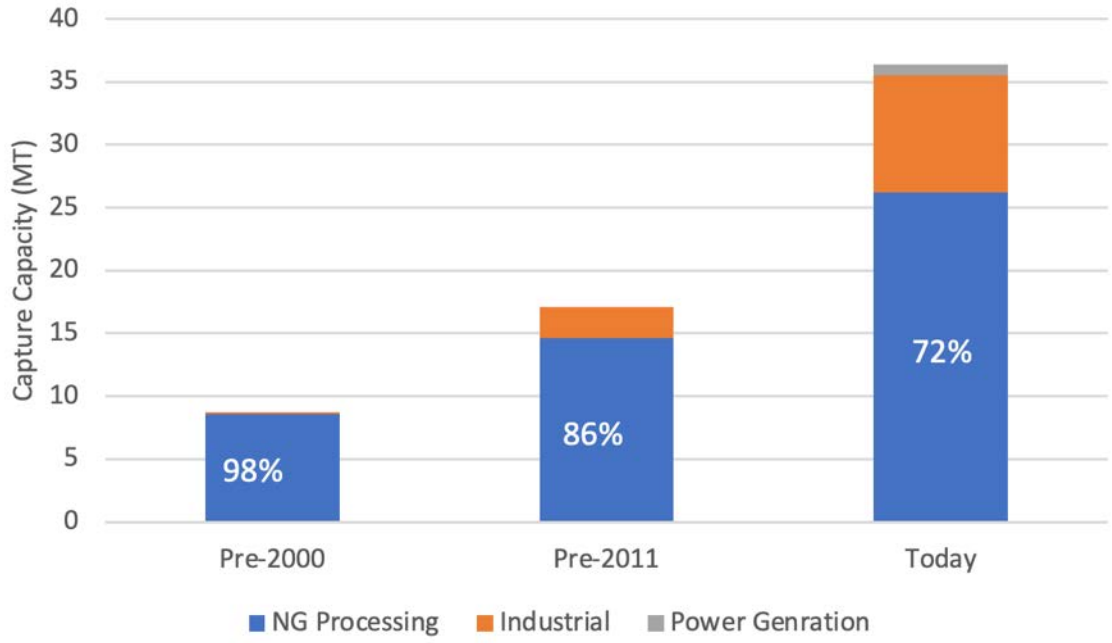
Looking back a decade, the figure was about 86% before 2011 and more than 98% pre-2000 (Figure 5). These figures demonstrate the historical dominance of natural gas processing as an application of carbon capture technology.

The key point about this application of CCS/CCUS is that producing the primary usable product (i.e., natural gas) is not possible without separating CO_2.

The extracted raw gas from any gas field has CO_2 content ranging from less than 3%[23] to 80%[24] in rare cases. This needs to be removed to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Therefore, capturing carbon was a part of the production process for oil and gas companies, regardless of the ultimate disposal or use of carbon dioxide (i.e., venting or using it for another purpose).

[23] IEEFA. Should Santos' Proposed Barossa Gas 'Backfill' for the Darwin LNG Facility Proceed to Development? March 2021.
[24] Energy Procedia. Worldwide development potential for sour gas. April 2011.

Figure 5: Historical Natural Gas Processing Share in CCS/CCUS Applications



Source: Global CCS Institute 2021,[25] IEEFA.

From a historical perspective, climate concerns did not figure in CCUS/CCS projects commissioned before the mid-1990s. In fact, the narrative around CCUS/CCS projects before the global community started to take climate change risks more seriously (i.e., since the Kyoto protocol of 1997) was more about economics than the environment. The only thing is that since the 1970s, oil and gas companies have decided to derive value from a CO_2 by-product, which used to be vented.

The reason was that in the 1970s and early 1980s, a massive supply shortage in the oil market—due to Iran's revolution and its consequent war with Iraq—pushed oil prices up dramatically. Oil companies, on the other hand, were seeking to increase the dropped production rate from their depleting oil wells in the U.S. Pumping CO_2 into the depleted wells to enhance the oil recovery was a promising solution.

Abundant captured CO_2 from the natural gas processing plants was among the most important driving forces behind developing CO_2-EOR technologies. Shute Creek Treating Facility in the U.S., the largest CCUS/CCS facility (7Mtpa) in the world, belongs to this era.

[25] Excluding suspended Lost cabin and Petra Nova Projects.

The economic narrative of using CO_2 for EOR gradually started to change in the 1990s towards an environmental one that sees carbon capture as a climate solution. The Sleipner project, commissioned in 1996, was the first carbon capture project with a dedicated geological structure (CCS), and the ultimate destination of captured CO_2 was a saline formation. Furthermore, it was the first project capturing CO_2 and not using it for EOR.

Due to the regulatory and business environment in Norway, Sleipner has been among the most successful projects of its kind, followed by another Norwegian project, Snøhvit, commissioned in 2007.

With the changing narrative, some authorities started to regulate oil and gas developments conditional on having a CCS facility to capture and sequester the CO_2 emissions of the field. The failed Gorgon project in Australia is an example.

Case Studies

In this section, we review Shute Creek, Sleipner, Snøhvit, and Gorgon in terms of their performance, history and economics.

Shute Creek

The Largest and the Third Oldest CCUS Project in the World

Shute Creek was commissioned in 1986 by ExxonMobil near the LaBarge field in southwest Wyoming, U.S. Gas from the field comprises just 21% methane (regarded as the marketable gas) and 65% CO_2—as such, it is considered among the highest CO_2 and lowest thermal energy content commercially produced gas in the world.

For Shute Creek's business model to work, considering revenue streams from selling products other than methane was inevitable. There was abundant CO_2 from LaBarge and, at the time of commissioning, nearby fields in Colorado and Wyoming were thirsty for CO_2 for enhanced oil recovery (EOR). Carbon capture was integral to the business model's cash generation.

Oil prices were high when the project was conceived in the early 1980s. After the project was commissioned, the tacit assumptions of long-term high oil prices and of oil producers' ongoing inflated demands for CO_2 for EOR were proved in error with two decades of a bearish oil market with low prices.

Shute Creek became a "Sell or Vent" project.

Shute Creek became a "Sell or Vent" project. It could either sell the CO_2 to third parties or vent the CO_2 when prices were low and EOR was uneconomic. The excess CO_2 that could not be sold for EOR has been vented over the years.

As part of the Shute Creek Treating Facility, the carbon capture plant originally captured about 4.3Mtpa.[26] In 2008, the Oil and Gas Conservation Commission questioned Exxon's effort to market the CO_2 and examined possible changes to the permit to vent. Exxon started an expansion project, completed in 2010, that delivered 50% more capture capacity (6–7Mtpa).[27]

With a nominal capacity of about 7Mtpa, Shute Creek is the world's largest CCS facility.[28]

[26] ZeroCO2.no. Shute Creek.
[27] Massachusetts Institute of Technology. LaBarge Fact Sheet: Carbon Dioxide Capture and Storage Project.
[28] Global CCS Institute. Global Status of CCS 2020. 2020.

The plant has captured more anthropogenic CO_2 than any other carbon capture project in the world[29] but it belongs to an era in which there was little public discussion about climate change and little climate-friendly motivation behind commissioning such projects.

Economics and Performance

The original cost for the whole Shute Creek Treating Facility, including the capturing facility, was US$170 million. In 2010 an extra US$86 million was provided to expand the carbon capture facility from 4.3Mtpa to 7Mtpa.[30]

In February 2022, ExxonMobil made the final investment decision to expand its carbon capture at La Barge by 1.2Mtpa at an estimated cost of $400m. It is expected that the expansion will be operational by 2025.[31]

The gas composition entering Shute Creek is 65% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulphide (H_2S) and 0.6% helium. The Shute Creek Treating Facility separates CO_2, methane and helium for sale. Concentrated acid gas stream, which includes 40% CO_2, is also injected into a carefully selected section of the same reservoir removing and storing approximately 0.4MT of CO_2 per year that is not sold for EOR.

The facility was not planned to have a dedicated geological structure for CO_2 storage, accounting for its "Sell or Vent" status. Were there a customer to buy the CO_2, it would be captured, compressed and transported. With fewer customers in the time of low oil prices, the excess captured CO_2 would be vented.

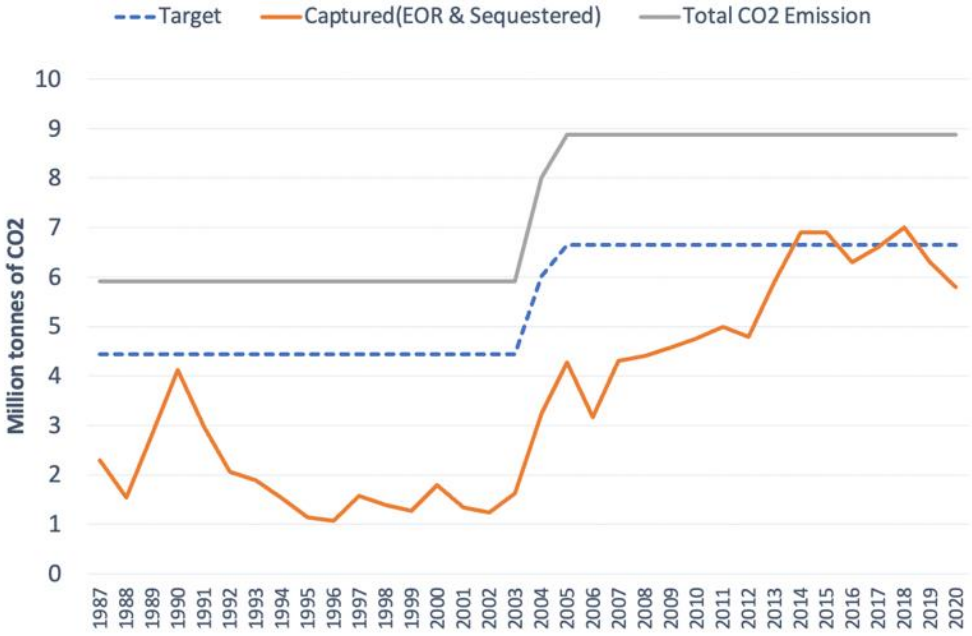
In the first 17 years of weak oil prices, from the beginning of the project to 2003, the plant rarely captured and sold more than 2Mtpa. Since then, soaring oil prices enabled Shute Creek to sell more of its CO_2 for EOR, volumes increasing until 2014 in step with historically high oil prices. From 2014 to 2020, despite oil prices starting to fall, ExxonMobil still managed to sell a high volume of CO_2 for EOR.[32]

Figure 6 summarises the performance of the Shute Creek CCUS plant over its 35-year lifetime. Despite its improved performance over recent years, the plant has reached its capturing capacity target (about 75% of total CO_2 emissions) in only a few of those years. At all other times, the plant has fallen short, mostly by a wide margin.

On average, the Shute Creek CCUS facility has fallen short of its capacity by about 36% over its lifetime, translating to approximately 66MT of CO_2 released into the atmosphere. Essentially, just half of CO_2 emissions captured and the other half vented.

[29] Global CCS Institute. Global Status of CCS 2021. 2021.
[30] IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022.
[31] Exxon Mobil. ExxonMobil to expand carbon capture and storage at LaBarge, Wyoming, facility. 25 February 2022.
[32] ExxonMobil. Energy and Carbon Summary. 2021, 2020, 2019.

Figure 6: Capturing Performance Trend of the Shute Creek CCUS Plant (1987–2020)



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. -- Energy Procedia.

Figure 7 provides a lifetime performance snapshot of the Shute Creek CCUS plant.

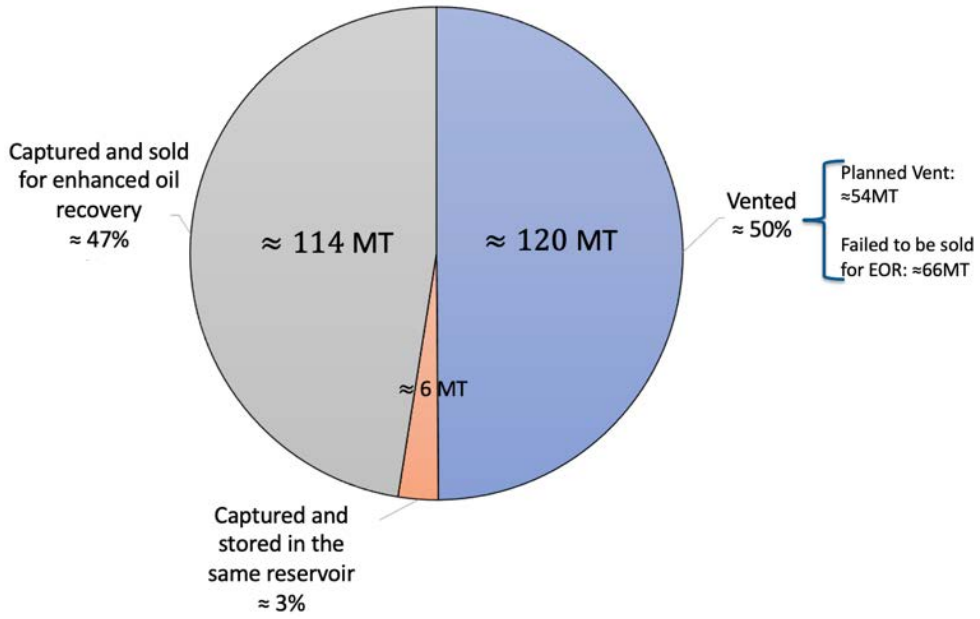
To the end of 2020, IEEFA estimates the treating facility on its own directly produced 240MT of CO_2, of which about 47% (114MT) was captured and used to recover oil (EOR).

Over its lifetime, about 3% of total CO_2 emissions has been sequestered in the same geological formation from which the feeding gas is extracted. The remaining 50% of the CO_2 content of the Shute Creek gas, estimated at about 120MT, has been vented. These numbers suggest that the CCUS plant has reduced the gas at the Shute Creek field only from extremely high CO_2 content (65%) to very high (33%).

To put it into perspective, that figure of 120MT is greater than the combined national emissions of Norway, Sweden and Finland in 2018, according to the World Bank.[33]

[33] The World Bank. CO_2 emissions(kt) – Norway, Sweden, Finland.

Figure 7: Shute Creek CCUS Lifetime CO_2 Capture Performance



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. – Energy Procedia.

Sleipner and Snøhvit: Norwegian Successful Experiences

Sleipner

Sleipner CO_2 Storage Project, commissioned in 1996 and located in the Central North Sea between the UK and Norway, was the world's first commercial carbon capture project with a dedicated geological structure for CO_2 sequestration.[34] It was also the world's first demonstration of CCS technology for a deep saline storage reservoir and the first large-scale CCS project to become operational in Europe.[35] To date, it has been among the world's most successful (if not the most successful) carbon capture projects, reaching its target capacity throughout many years of operation with no evidence of leakage or harmful CO_2 movement in the formation.

The natural gas produced from the Sleipner West field contains 4–9% CO_2, so needing to be reduced to less than 2.5% to produce marketable gas. The additional proportion of the CO_2 content of the extracted gas from the field is captured and pumped back to the Utsira geological storage, a 200–250 metres thick massive sandstone formation. The

[34] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[35] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.

estimated storage capacity is 600 billion tonnes of CO_2. Studies have shown that there is no leakage of the CO_2 from this formation into other horizons.[36]

The main motivation for adding this extra step in the hydrocarbon processing facility there—instead of venting the gas—was the Norwegian CO_2 tax introduced in 1991.

The capturing and injection capacity of the project is between 0.85Mtpa[37] and 1Mtpa[38] as cited by different sources.[39, 40] The project stakeholders are Equinor as the operator (~58.3%), ExxonMobil (~17.2%), LOTOS Exploration and Production Norge (15%) and KUFPEC (~9.4%).[41]

The experience from Sleipner was effective in designing and implementing different regulatory frameworks for carbon storage around the world. For example, it was used as a guide for the EU Directive on geological storage of carbon dioxide (adopted by the European Parliament in 2009). Amendments to the London Protocol and the Convention for the Protection of the Marine Environment of the North-East Atlantic (or OSPAR Convention) to allow for CO_2 storage in offshore geological formations also used the Sleipner project as a benchmark.[42]

Snøhvit

Snøhvit is a liquefied natural gas (LNG) development in the Barents Sea off northern Norway, commissioned in 2007. The extracted gas contains 5–8% CO_2 by volume, which is solidified into dry ice under the pressure and temperature conditions of liquefying natural gas and therefore must be removed before the gas is processed into LNG.

As the Norwegian government mandated CCS as a condition to approve Snøhvit's licence, Equinor, the operator of the project, proceeded on a carbon capture project to avoid venting the separated CO_2 from the field. Instead of venting, after the unprocessed raw natural gas stream is transported 143km to shore into the Hammerfest LNG plant in the far north of the country to be liquefied, the removed CO_2 is pumped back to the Snøhvit field offshore through a separate pipeline, to be injected in the geological reservoir 2600 metres beneath the seabed. The company says "a shale cap which lies above the sandstone will seal the reservoir and ensure that the CO_2 stays underground without leaking to the surface".[43]

The LNG project consists of nine wells, eight for production and one for injecting CO_2. The removal process at the LNG plant is designed to capture 0.7Mtpa of CO_2 at full

[36] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[37] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[38] Sintef. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[39] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[40] Ola Eiken. Twenty years of monitoring CO_2 injection at Sleipner. In Thomas L. Davis, Martin Landrø, Malcolm Wilson (Eds). Geophysics and Geosequestration. Cambridge University Press. 9 May 2019.
[41] Equinor. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[42] Institution of Civil Engineers. Sleipner carbon capture and storage project. 3 February 2017.
[43] Equinor. Carbon storage started on Snøhvit. 23 April 2008.

capacity. Injection of CO_2 started in April 2008, a year after the gas plant started production.[44] In early 2010, It was announced that it had discovered that there was less storage capacity than expected at the Snøhvit injection site.[45]

A fire in September 2020 at the Hammerfest LNG plant led to it being shut down for more than 18 months.[46] It has resumed operation recently and is preparing to produce LNG again.[47]

Economics and Performance

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Carbon Dioxide Tax

The key drivers that enabled these two projects to proceed were the CO_2 tax and climate quota obligation, introduced by the Norwegian government in 1991 and 2005, respectively.

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Norway was one of the first countries in the world to impose a CO_2 tax, legislated in the Act on Tax on CO_2 Emissions in Petroleum Activities on the Continental Shelf. This requires companies to pay a CO_2 tax on the combustion of gas, oil, and diesel in petroleum activities in the designated offshore area, as well as on CO_2 or natural gas emissions.[48]

For 2022, the tax rate is NOK 1.65 per standard cubic metre of gas or per litre of oil or condensate. For combustion of natural gas, this is equivalent to NOK 705 per tonne of CO_2. For emissions of natural gas, the tax rate is NOK 1066 per standard cubic metre.[49]

The government in its new climate plan for 2021–2030 has announced that the total CO_2 price of emissions will increase in line with the increase in the tax on non-ETS (Emissions Trading System) emissions subject to an emissions tax, so the total CO_2 price in 2030 will be about NOK 2000/tonne measured in fixed 2020 NOK—almost three times the current price.[50]

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[44] Global CCS Institute. Global Status of CCS: Special Report. Introduction to Industrial Carbon Capture and Storage. June 2016.
[45] Massachusetts Institute of Technology. Snohvit Fact Sheet: Carbon Dioxide Capture and Storage Project.
[46] Reuters. Norway LNG plant restart faces new delay in blow to Europe's gas supply. 31 January 2022.
[47] Offshore Engineer. Norway's Hammerfest LNG Plant Resumes Operation After 20-month Outage. 27 May 2022.
[48] Norwegian Petroleum. Emission to Air. Updated August 2021.
[49] Norwegian Petroleum. The Government's Revenues. Updated May 2022.
[50] Ministry of Climate and Environment. Norway's comprehensive climate action plan. 1 August 2021.

Quota Obligation

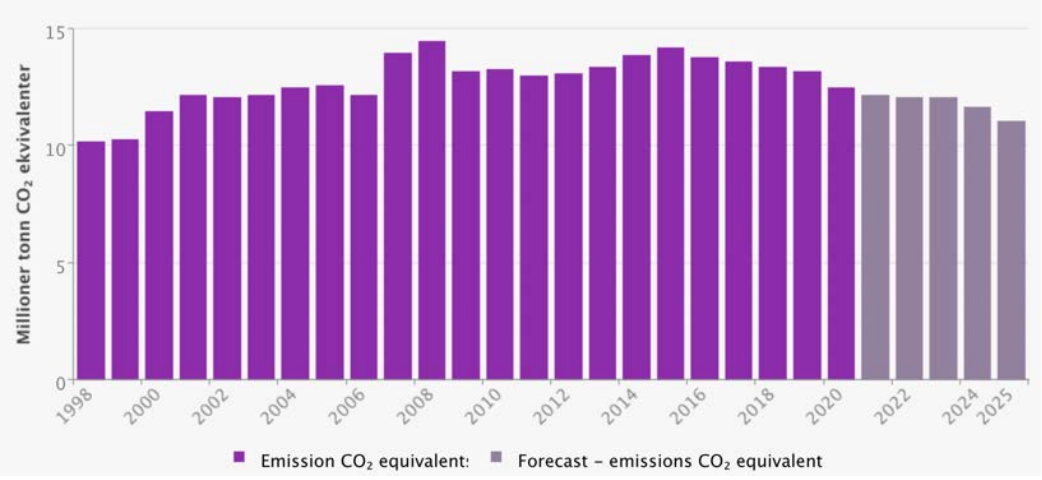
The Climate Quota Act, enacted in 2005, connects Norway to the EU's quota system for greenhouse gas emissions, and the country joined the European Emission Trading System in 2008. Norwegian companies are subject to the same quota obligations as those in the EU. The system is currently in its fourth period, which runs until 2030.[51]

The EU quota system establishes a maximum level of total emissions. This ceiling is reduced on an annual basis to ensure that the system contributes to the system's set emission target when the relevant quota period expires. Quotas are either auctioned or allocated free. In recent years, the CO_2 price in the EU quota system has been increasing, putting a greater burden on polluters.

The combination of the CO_2 tax and quota obligation means that the companies on the continental shelf are facing an extremely high price per tonne for emitting CO_2. The figure is significantly higher than the tax most companies in other sectors must pay in Norway and massively higher than the obligations on similar oil and gas companies in other countries with fossil-based economies.

With these instruments in place, emissions from the Norwegian petroleum sector have been virtually stable during the past decade (Figure 8) with relatively stable oil and gas production (Figure 9). Under the effect of coming, more stringent regulations, emissions are expected to decrease. The Norwegian Ministry of the Environment has described CO_2 taxes as the most important tool for reducing emissions.[52]

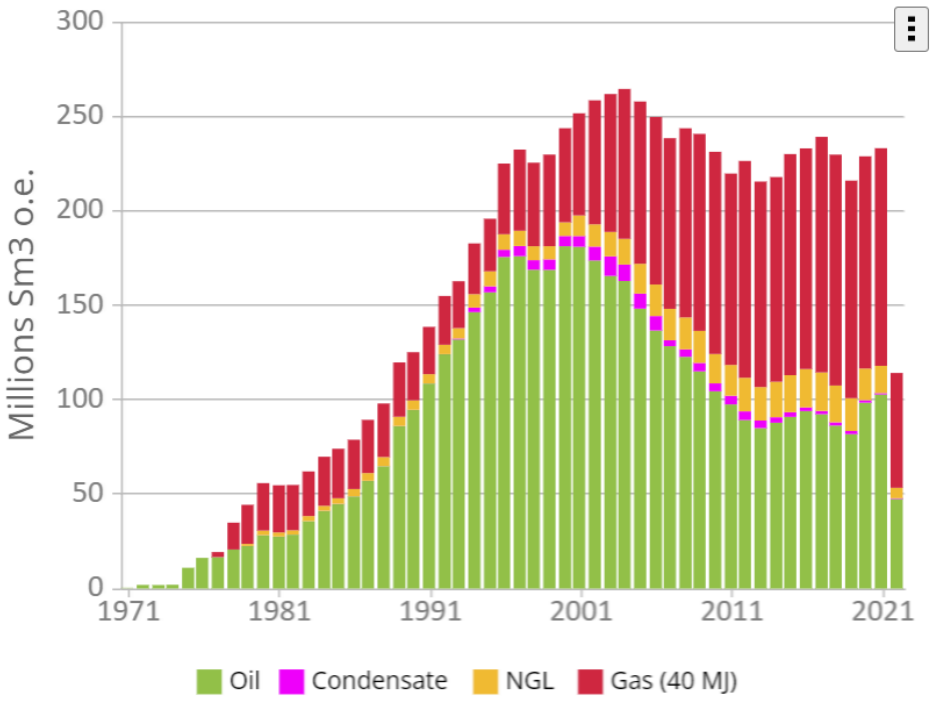
Figure 8: Emissions of Greenhouse Gases from the Norwegian Petroleum Sector



Source: Norwegian Petroleum, Emissions to Air.

[51] European Commission. EU action against climate change. EU emissions trading — an open system promoting global innovation. 2007.
[52] Norwegian Ministry of the Environment. Norway`s Fifth National Communication under the Framework Convention on Climate Change. Status report as of December 2009.

Figure 9: Norwegian Petroleum Production



Source: Norwegian Petroleum Directorate.

CCS Was Financially Viable for Norwegian Cases

The regulatory framework that was the main motivation for these CCS projects in turn made them economic and pushed the oil and gas industry to adopt CCS in extraction facilities.

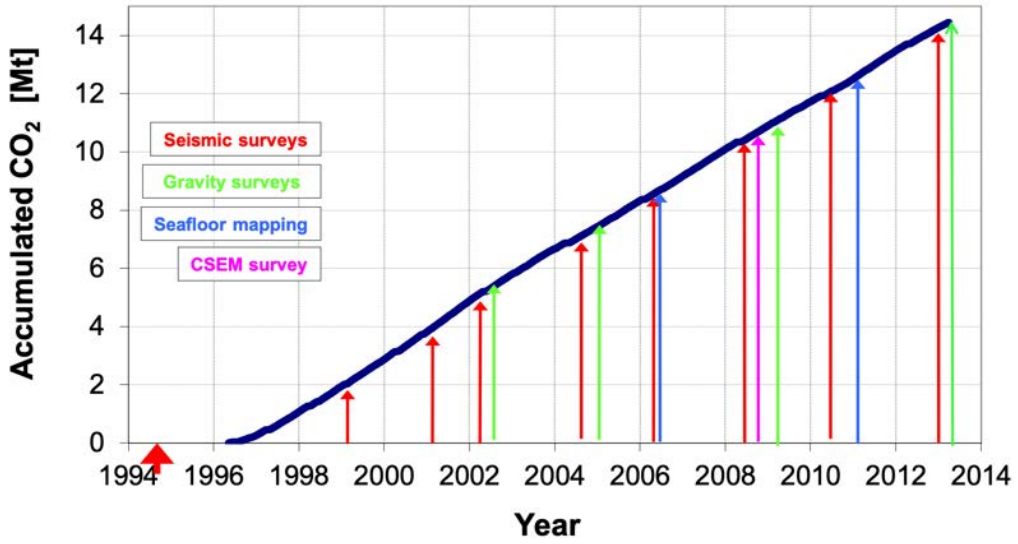
When the Sleipner CCS project was commissioned in 1996, five years after the Norwegian government introduced the carbon tax, the levy on natural gas processing in the North Sea petroleum extraction sector was US$49 per tonne of CO_2.[53] Had the operators vented, for example, 1MTof CO_2 in that first year, the tax bill would have been US$49 million. On the other hand, the additional investments to compress and inject the removed CO_2 amounted to about US$100 million in 1996).[54] Injecting CO_2 was estimated to cost about $17 per tonne.[55] Considering injection averaged about 0.9Mtpa, the partner companies could have recovered the capital cost and operating injection cost of the project in the first few years of the project.

[53] Annegrete Bruvoll og Bodil Merethe Larsen. Greenhouse gas emissions in Norway: Do carbon taxes work? Statistics Norway, Research Department. Discussion Papers No. 337. December 2002.
[54] Olav Skalmeraas. Vice President CCS, Statoil. Sleipner carbon capture and storage project. In ICE Group. 3 February 2017.
[55] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.

The same 'carrot and stick' measures applied to the Snøhvit project, with millions of dollars saved in avoiding the carbon tax while complying with stringent emission regulations.

The Sleipner CCS project has operated consistently near its capturing capacity. Figure 10 shows the project's capturing performance up to 2014. It demonstrates the steady performance of the carbon capture facility.

Figure 10: Sleipner CCS Injection and Monitoring History (1994–2014)



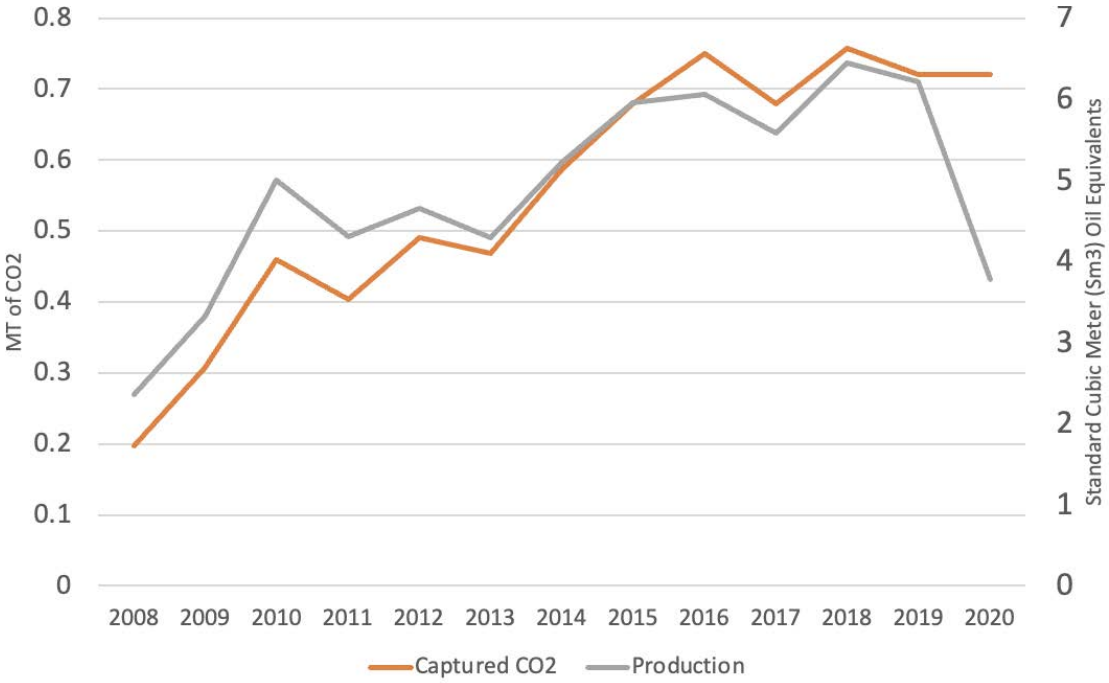
Source: Statoil, The Sleipner CCS Experience, 2014.

Snøhvit's capturing rate has been increasing since its commissioning in 2008, surpassing its capture target of 0.7Mtpa in recent years. Figure 11 shows the capture performance of the project. The reason that Snøhvit had been capturing less than its 0.7MT nominal capacity in the early years of the project was not due to its underperformance. This is evident from the gas production level of the project from which Snøhvit CO_2 is sourced (second axis of Figure 11). The correlation between the production and capturing rates confirms the steady performance of the carbon capture facility with its nominal capacity in recent years, where the production of the field stands at its maximum as well (Figure 11).

Since commissioning in 2008, Snøhvit has captured more than 7MT of CO_2, averaging 0.55–0.6MT annually.[56]

[56] Olav Skalmeraas. Sleipner carbon capture and storage project. 3 February 2017.

Figure 11: Snøhvit Project: Production vs Captured CO_2



Source: Norwegian Petroleum, Snøhvit. Environmental Science and Technology Letters, 2022.

Figure 12, based on Equinor's 2021 sustainability report, demonstrates the total CO_2 captured and stored per year by the projects it operates. Cumulative capacity of Snøhvit and Sleipner is depicted as the orange line in the graph. Other than in the past two years, there is a consistent trend in capturing carbon.

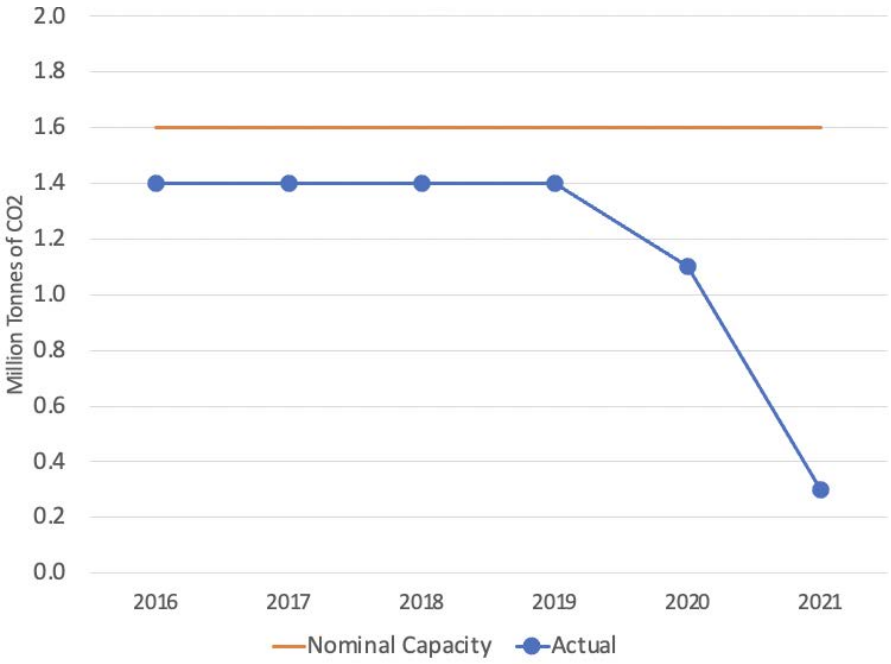
The drop in capturing rate in 2020 and 2021 was due to the fire in September 2020[57] in the Hammerfest LNG plant, which fed CO_2 back to Snøhvit. The low capture for those years is not related to the CCS plant underperformance.

Moreover, Sleipner field's production has been in its late tail phase[58] throughout the last decade, otherwise the capture figures of the two projects would be at their 1.6MT nominal capacity.

In the past two decades, several research efforts on these two projects have reported no leakage or harmful movement of stored CO_2 in the reservoirs.[59, 60]

[57] Upstream. Hammerfest LNG plant to restart next week after shutdown extended by six days. 16 May 2022.
[58] Norwegian Petroleum. SLEIPNER ØST. Website accessed August 2022.
[59] Andy Chadwick, Rob Arts, Ola Eiken, Paul Williamson and Gareth Williams. Geophysical monitoring of the CO_2 plume at Sleipner, North Sea: An outline review. 2006.
[60] Andy Chadwick, Benjamin Marchant, and Gareth Williams. CO_2 storage monitoring: leakage detection and measurement in subsurface volumes from 3D seismic data at Sleipner. 2014.

Figure 12: Snøhvit and Sleipner Projects: Carbon Capture Performance (2016–2021)



Source: Equinor Sustainability Report, 2021.

Gorgon

World's Largest CCS Project

The Gorgon LNG project on Barrow Island off the Pilbara coast of Western Australia is the world's largest such projects, with export capacity of 15.6MT of LNG and provides the state with up to 300 terajoules (TJ) of domestic gas daily.[61]

The plant was planned to be equipped and simultaneously started with the world's largest carbon capture project with dedicated geological structure in 2016.[62]

It has a nominal maximum capacity of 4Mtpa accounting for 40% of the capacity of all CCS projects with dedicated geological storage operating around the globe.[63] The Gorgon CCS project was initially planned to capture and inject underground more than

[61] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project. Website accessed August 2022.
[62] Massachusetts Institute of Technology. Gorgon Fact Sheet: Carbon Dioxide Capture and Storage Project.
[63] Global CCS Institute. Global Status of CCS 2021. 2020.

100 million tonnes of CO_2 over its life. This was supposed to reduce Gorgon's greenhouse gas emissions by about 40%.[64]

The CCS project was meant to start operations concurrently with the LNG plant in March 2016, though several technical problems meant CCS injection did not start until August 2019. As a result, the facility completely missed its targets for the first three and a half years.

The Gorgon Project is a joint venture between the Australian subsidiaries of Chevron, the operator (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and JERA (0.417%).[65]

Economics and Performance

The Gorgon CCS project started with great fanfare, both as Australia's largest project and as the world's largest CCS project with a dedicated geological structure. It received $60 million from the Australian government as part of the Low Emissions Technology Demonstration Fund.[66]

The $3.1 billion Gorgon plant produced its first LNG cargo in March 2016[67] but the first CO_2 injection from its CCS facility[68] did not occur until three and a half years later. Start-up checks in late 2017 found leaking, corroded valves and excess water in the pipeline between the LNG plant and the injection wells, a potential cause of corrosion.[69]

Technical problems did not end there. In January 2021, it was reported[70] that the WA Department of Mines, Industry Regulation and Safety had ordered Gorgon to reduce the volume of carbon captured by the project, due to structural issues. Essentially, sand was blocking the well that reinjects water underground, compromising the crucial pressure management system.

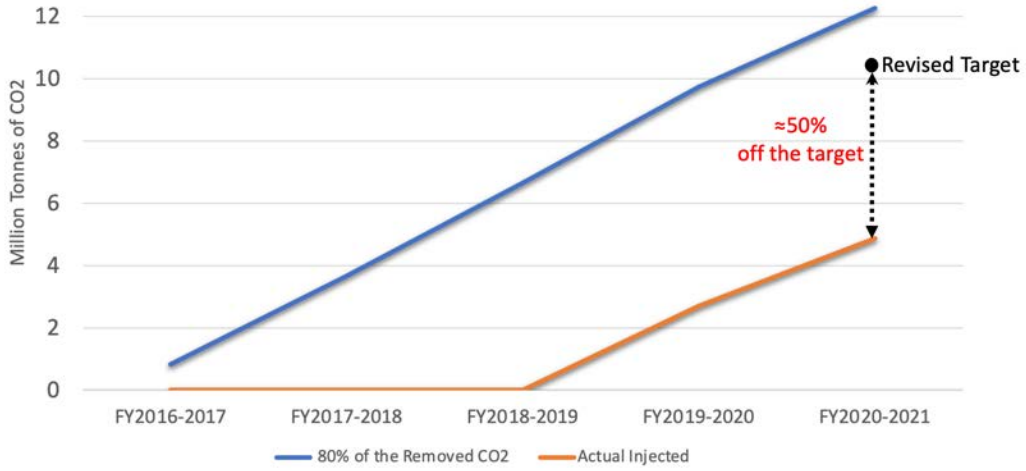
A closer look at Gorgon's CCS target and results demonstrates the project's considerable underperformance in the first five years. Calculated on a five-year rolling average commencing on 18 July 2016, Chevron committed to ensure that at least 80% of reservoir CO_2 removed during processing at the gas treatment plant, that would otherwise be vented to the atmosphere, would be injected underground.[71] On this

[64] Chevron. Gorgon Gas Development and Jansz Feed Gas Pipeline Five-year Environmental Performance Report 2015–2020. October 2020, p. 4.
[65] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[66] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[67] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[68] Financial Times. Monster problem; Gorgon project is a test case for carbon capture. 26 July 2021.
[69] The West Australian. Carbon hiccup for Chevron with 5 million-tonne greenhouse gas problem at Gorgon LNG plant. 19 December 2017.
[70] Boiling Cold. Chevron's Gorgon emissions to rise after sand clogs $3.1bn CO_2 injection system. 12 January 2021.
[71] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.

basis, the Gorgon CCS plant should have captured at least 12.3MT of the removed CO_2 in its five years of operation.

The environmental performance reports show that the plant had injected only 4.9MT by July 2021. The shortfall from the five-year target is claimed to be 5.23MT CO_2.[72] Putting all this together, it can be inferred that the Gorgon CCS project's revised target for the first five-year period was about 10.1MT and it failed to meet this target by about 50% (Figure 13 shows the cumulative trend of Gorgon's sequestered CO_2 versus the cumulative target trend).[73]

Figure 13: Gorgon CCS Plant's Performance (Cumulative Trend, 2016–2021)



Source: Gorgon Environmental Performance Reports 2015–2020 & 2021

In the Gorgon 2021 environmental performance report, Chevron cited planned and unplanned maintenance among other causes for the underperformance of the plant.[74]

Gorgon's technical troubles and ongoing "unplanned" maintenance after five years illustrate some of the inherent and unique risks of CCS, despite the technology's decades of operation.

Gorgon has recently agreed to acquire and surrender credible greenhouse gas offsets recognised by the West Australian government to offset its target shortfall of 5.23MT of CO_2. Estimates of what this may cost Gorgon vary from US$100 million to US$184 million.

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[72] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.
[73] In its latest environmental performance report published in November 2021, four months after the first five-year period ended, Chevron stated that 5.5MT had been injected in the five years of the project's lifetime.
[74] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 44.

The project is expected to run for 40–45 years, after which there will be a closure period of 15 years. Post-closure, liability will be handed over to the WA government.

The project also has failed to reach its five-year rolling average (ending July 2022) target.[75]

Other Big CCS/CCUS Project Failures in the Natural Gas Processing Sector

Apart from the operating projects, several projects in this sector have failed or been suspended due to technical issues and/or environmental concerns. A case in point is the In Salah project in Algeria.

In Salah

The In Salah project in Algeria was a CCS project with a total cost of US$2.7 billion. Equinor (Previously Statoil) was the operator, and the announced capture capacity was 1–1.2Mtpa.[76]

Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal. Nevertheless, the project successfully stored 3.8MT of CO_2 in the Krechba Formation during its lifetime.[77]

Analysis of the reservoir, seismic and geo-mechanical data from 2010 led to the decision to suspend CO_2 injection in June 2011. Concerns about possible vertical leakage into the caprock led to an intensified R&D program to understand the geo-mechanical response to CO_2 injection at this site.[78]

Lost Cabin is another example of a project in which CO_2 injection was suspended in 2018. It was a CCUS project (CO_2-EOR) with a capacity of 0.9Mtpa started in 2013 in Fremont County, Wyoming, U.S. ConocoPhillips and Denbury were the companies involved in the project.[79]

Just after five years of operation, in 2018, a fire occurred at the Lost Cabin Gas Plant in Wyoming, resulting in the shutdown of the plant's CCUS facility. There was an expectation that operations would restart by the end of 2020 with a lower capture

[75] The Guardian. Gas giant Chevron falls further behind on carbon capture targets for Gorgon gasfield. 16 July 2022.
[76] In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[77] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[78] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[79] Lost Cabin Fact Sheet. Commercial EOR using Anthropogenic Carbon Dioxide.

rate of 0.7Mtpa.[80] But it did not happen, and the latest Global CCS Institute report, published in late 2021, still labels the project as suspended.[81]

Enhanced Oil Recovery Business Dominates Natural Gas Processing Sector

Natural gas processing has been the main CCS/CCUS application historically, with about 70% of current total operational capacity worldwide. The first CCUS project, Terrel, established in 1972, was in the U.S.

Developing such projects was not about environmental or climate concerns in the 1970s. Separating CO_2 from extracted raw gas is essential to producing marketable and flammable natural gas. It was/is a technical must.

Further, during the energy crisis in the 1970s and 1980s, the interest in capturing the separated CO_2 and selling it to oil companies to enhance the rate of their oil production started to increase. It was a win-win deal for both gas producers who could increase their revenue by selling a previously vented CO_2 to oil companies and for the oil companies who could revitalise their ageing depleted oil wells and get more oil out of them to sell in those eras of the bullish oil market. Hence, economics was the second incentive behind developing such projects in that era.

This is evident in the share of carbon capture projects servicing EOR activities (CCUS) compared to the carbon capture projects with dedicated geological storage for sequestering the carbon without using it for EOR(CCS). Nevertheless, more than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

More than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

And as EOR is about producing more oil and gas, encouraging investment in these fossil fuels negates the very initial claimed emission reduction goal for carbon capture technology.

Scope 3 Emissions—the Elephant in the Room

Gas processing CCS/CCUS covers a tiny proportion of the value chain emissions compared to CCS/CCUS in other sectors.

As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is *not* about reducing Scope 3 emissions from the final

[80] Global CCS Institute. Global Status of CCS 2020.
[81] Global CCS Institute. Global Status of CCS 2021.

combustion/use of gas. Rather it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels, whether by combustion or as feedstock materials.[82]

Therefore, giving the green light to new oil and gas projects just because of CCS/CCUS promises attached to those projects is not climate friendly.

Even if the CCS/CCUS facilities work at their capacity (which was not the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions they themselves produce by adding CCS/CCUS.

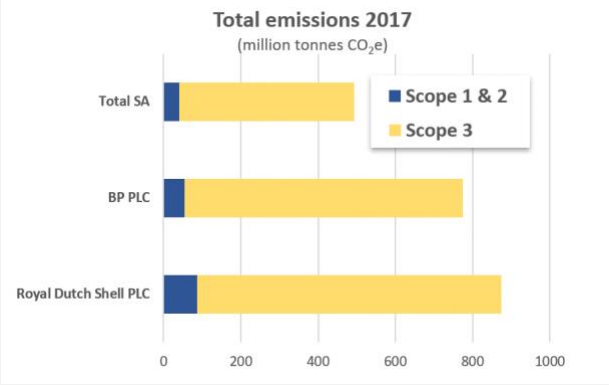
The gas burnt at the end of the value chain produces the biggest chunk of emissions, which CCU/CCUS proposals do not address.

Scope 1, 2 and 3 Emissions

Value chain emission of different products is categorized into three different scopes, as outlined by the Green House Gas (GHG) Protocol Corporate Standard.

Scope 1 emissions constitutes emissions from sources owned or controlled by the producer company. Scope 2 represents indirect emissions from purchased energy inputs such as electricity or heat which are not generated directly by the company. Scope 3 represents all other emissions in the value chain, including those located in the upstream (input) and downstream (output) part of the company's process.

Specific for companies involved in energy *extraction*, it is important to note that the end product emissions (Scope 3) constitute a much greater portion of the overall (Up to 90%). Below chart further illustrates the typical emission scopes for oil & gas companies.



Source: Trucost, S&P Global Market Intelligence.

[82] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

Lessons Learned

In general, due to its association with EOR and historic capture rate issues,[83, 84] carbon capture in the natural gas processing sector has minimal environmental and social credibility as a decarbonisation option.

The most obvious point is that there is no more room for a new EOR project (CCUS) as it contradicts net-zero goals and emission reduction activities. In contrast, EOR has been the central part of the carbon capture application in this sector and others historically.

A new EOR project (CCUS) contradicts net-zero goals and emission reduction activities.

What about capturing and storing carbon without using it for oil production (CCS)?

As clearly stated in the seminal IEA's Net Zero 2050 report,[85] there should be no new oil and gas field developments if the world wants to reach net zero by 2050 and avert the catastrophic consequences of climate change. Therefore, any new oil and gas development should not get a green light, with or without CCS.

Even if a CCS project could capture a majority of the oil and gas facilities' emissions (which most projects show is unlikely), it could only capture 10–15% of the value chain emissions of oil and gas produced by those fleets (i.e., Scope 1 and 2 emissions). Roughly 80–90% of the emissions are Scope 3 emissions,[86] and CCS projects cannot do anything about that.

The niche remainder of existing gas processing units are not 'new' and would be operating through the next one or two decades until renewables, green hydrogen and battery technologies take up the whole energy system. They might provide cases to think about, but there are still risks associated with these.

There is no confidence that the proposed CCS projects could meet their designed capture rates. Except for a few successful cases in a unique regulatory environment, such as Norway, with high carbon taxes and stringent environmental regulations, the history of carbon capture technology is full of failed or underperformed projects. This report has studied some of the biggest ones.

There is also no room to bet billions of dollars on projects that could not meet expectations. Instead, there are proven, cost-effective, and established investment alternatives to battle climate change, such as solar and wind energy.

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[83] Robertson and Mousavian. IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022, pp. 18–20.
[84] IEEFA. Gorgon Carbon Capture and Storage: The Sting in the Tail. April 2022.
[85] IEA. Net Zero by 2050. May 2021.
[86] Robertson and Mousavian. IEEFA. Santos 2022 climate change report. 1 April 2022.

The other problem with CCS projects is the availability of suitable geological storage locations nearby the projects to make the finance of CCS work.

Monitoring is another challenge—the trapped CO_2 underground needs monitoring for centuries to ensure it does not come back to the atmosphere. Leakages and fugitive emissions in the long term are serious risks. It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere. There are several real-world examples of failure in keeping gas underground. The best example is the California Aliso Canyon gas leak in 2015, the worst man-made greenhouse gas disaster in U.S. history when 97,000MT of methane leaked into the atmosphere.[87] The other one is the In Salah project in Algeria, which was a CCS project with a total cost of US$2.7 billion.[88] Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal and suspicious movements of the trapped CO_2 under the ground.

It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere.

There will always be a risk of such disasters for any CCS project. The IPCC's Carbon Dioxide Capture and Storage Special Report stated:

> *"CO_2 storage is not necessarily permanent. Physical leakage from storage reservoirs is possible via (1) gradual and long-term release or (2) sudden release of CO_2 caused by disruption of the reservoir."*[89]

The other challenge is liability. The question of who will be responsible for long-term monitoring of the geological structure is crucial. Large oil and gas companies mainly benefiting from the gas developments must be liable for any failure/leakage and monitoring costs of CCS projects, specifically if they get subsidies, grants and tax credits for capturing the carbon.

The most recent example of the liability challenge is the Gorgon CCS project discussed earlier. The expected project life is 40–45 years, after which there will be a closure period of 15 years. Post closure, the Western Australian government,[90] essentially taxpayers, take over the project's liability.

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[87] The Washington Post. California gas leak was the worst man-made greenhouse-gas disaster in U.S. history, study says. February 2016.
[88] Massachusetts Institute of Technology. In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[89] Intergovernmental Panel on Climate Change. Carbon Dioxide Capture and Storage Report. 2005.
[90] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project.



Section 3: Carbon Capture Application in the Power Sector

As one of the highest emitting sectors, the power sector (electricity and heat production) had the largest increase in CO_2 emissions by sector in 2021. This accounted for 46% of the global increase in emissions in 2021. CO_2 emissions from the sector neared 14.6 gigatonnes (GT), their highest ever level.[91]

Power plants inherently emit large volumes of CO_2.

Power plants inherently emit large volumes of CO_2. For example, a 1 gigawatt (GW) coal plant could emit 5–7MT of CO_2 annually.[92]

The most recent proposed application for CCS/CCUS is retrofitting existing, and usually old,

[91] IEA. Global Energy Review: CO_2 Emissions in 2021. March 2022.
[92] Global Energy Monitor. Estimating carbon dioxide emissions from coal plants. Accessed on 3 February 2022.

fossil-based power plants with carbon capture technology to reduce their staggering emissions.

CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced by the string of historical issues in retrofitting CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2.[93] Small in concentration but large in terms of absolute volume globally.

Over the years, IEEFA has published a comprehensive body of knowledge in assessing the economics and viability of CCS/CCUS projects,[94] particularly its application in the power sector. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to consumers.[95] Under normal operation, power plants already consume a portion of the power they generate for self-use. CCS/CCUS impose additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

This also means that more fossil fuels will need burning to generate the same amount of electricity in a non-CCUS power plant. Decades of technological progress have been devoted to increasing coal power plant efficiency from the sub-38% of subcritical plants to the ~45% of Ultra Super Critical (USC) plants. A loss of 8–12% poses a substantial barrier for many CCS/CCUS applications.[96]

To be able to compete in the electricity market context, the high cost of CCS/CCUS projects will need compensation—by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and also could lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

Selling captured CO_2 for EOR contradicts the very goal of capturing carbon.

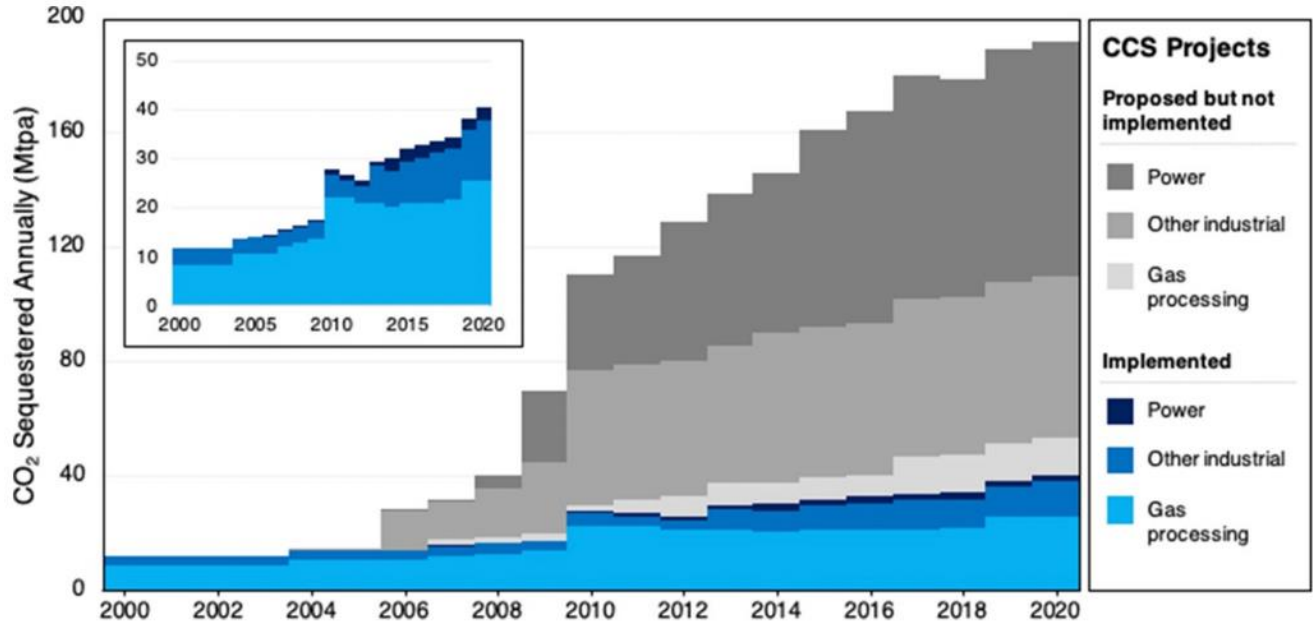
Government incentives could flow into fast-growing, efficient, and clean, renewable energy technologies and battery and storage sectors. Selling captured CO_2 for EOR contradicts the very goal of capturing carbon as it leads to producing fossil fuels. Moreover, considering the EOR business as a cash-generating business for power

[93] IPCC. Carbon capture utilization and storage. 2005. Energy Procedia. Comparison of solvents for post-combustion capture of CO_2 by chemical absorption. 2009.
[94] IEEFA. Carbon Capture and Storage.
[95] Energy consumption can be in the form of drawing steam from the power plant to heat solvent-based CCUS process.
[96] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

plant owners is a flawed assumption. EOR activities highly correlate with oil prices, and the demand for CO_2 would be as volatile as oil prices. IEEFA has elaborated on this issue in previous research.[97]

Apart from the financial side, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.[98] Figure 14 reflects the results of recent research by academic institutions and universities in Canada and the U.S. It depicts the failure of carbon capture technology in the power sector.

Figure 14: Global Implemented Annual CCS/CCUS Projects By Sectors



Source: Abdulla et al, 20201, Environmental Research Letters.

Globally, there is only one operating power generation CCUS, which is located at the Boundary Dam plant in Canada. A second CCUS plant, Petra Nova in the U.S., was operational between 2017 and 2020 and later reported to be "shut down indefinitely" after only four years.[99] Both of these plants have been studied in this report, and important lessons were elicited.

It might be the case that there are more proposals for CCUS projects in the power sector, especially as the narrative is becoming attractive in Southeast Asian countries with relatively young fossil power plant fleets. However, the historical lessons clearly suggest that no more greenfield coal or gas powerplants should be

[97] Robertson and Mousavian. IEEFA. Shute Creek – world's largest carbon capture facility sells CO2 for oil production, but vents unsold. March 2022.
[98] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[99] Reuters. Problems plagued US CO_2 capture project before shutdown: document. 7 August 2020. Yahoo Finance. Power plant linked to idled US carbon capture project will shut down indefinitely – NRG. 30 January 2021.

greenlit just because of an embedded CCS facility in its design plans. Also, in the case of CCUS proposals for existing and ageing power plants, to prevent them from getting stranded, investors should know that these projects will likely face financial and technical difficulties that will put them in trouble. The era of fossil-based power plants is over, and renewable technologies plus storage capabilities are the future solutions serving net-zero goals.

Case Studies

In this section, only two carbon capture projects ever operationalised in the power sector have been studied. As the power sector has a track record of failures in utilising carbon capture technologies to curb emissions, the Kemper coal gasification power plant, one of the biggest failures that led to the most expensive power plant ever built, has also been studied.

Petra Nova

The Only Post-combustion Project in the U.S. Was Shut Down After Four Years

There have been only two post-combustion CCS plants commissioned to date. The Petra Nova project was the second and the only one operationalised in the U.S. It was designed to reduce carbon emissions from a power plant southwest of Houston, Texas. Project partners NRG Energy and JX Nippon Oil retrofitted one the boilers at the W. A. Parish Generating Station—with post-combustion carbon capture treatment technology to manage exhaust emissions.

The 45-year-old powerplant has a total capacity of 3.7GW and the CCS was fitted in January 2017 to a boiler in its Unit 8 with 240 megawatts (MW) capacity.[100]

Citing low oil prices during the COVID-19 pandemic, the plant was shut down in May 2020,[101] a common issue with CO_2-EOR projects that are typically very sensitive to oil price volatility.

The amine-based absorption technology, developed by Japanese technology giants Mitsubishi and Kansai Electric Power[102] removes CO_2 from the exhaust gas through a basic absorber-stripper system, then compresses it into liquid. The captured CO_2 was piped 130km away to the sandstone Frio Formation of the West Ranch oil field and after being used to increase the rate of oil recovery, was stored at a depth of about 1500 metres.

As with most CCS projects in North America, generating cash from selling CO_2 for EOR was one of the main incentives for launching this project.

[100] U.S. Department of Energy, Petra Nova – W.A. Parish Project.
[101] NRG. Petra Nova Status Update, August 2020.
[102] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project.

To meet the Clean Coal Power Initiative requirements of the U.S. Department of Energy (DOE), the Texas Bureau of Economic Geology established a scheme for monitoring CO_2 injection and movement beneath the rock structures.

Economics and Performance

Installing the Petra Nova carbon emissions reduction system cost about US$1 billion. Known funding sources were US$190 million provided by the DOE in the form of grants and appropriation, US$250 million by Japanese banks as a loan and US$300 million invested by NRG Energy and JX Nippon Oil.[103]

The main enabler in its business model was the revenue from selling captured CO_2 to the adjacent oil field. This project was expected to run for at least 20 years to enhance the rate of oil production in the West Ranch field from less than 1000 barrels per day to more than 15,000 per day. When the project was first proposed, oil prices were very high (US$100 per barrel) and the very optimistic and unrealistic assumption, given the global transition away from fossil fuels, was that the price would not drop. In 2017, the oil price was about US$50 per barrel and there was a net loss from oil production at the field.[104]

On 1 May 2020, NRG shut down Petra Nova, citing low oil prices during the COVID-19 pandemic.[105, 106] The plant had also reportedly suffered frequent outages and missed its carbon sequestration goal by 17% over its short three years life.

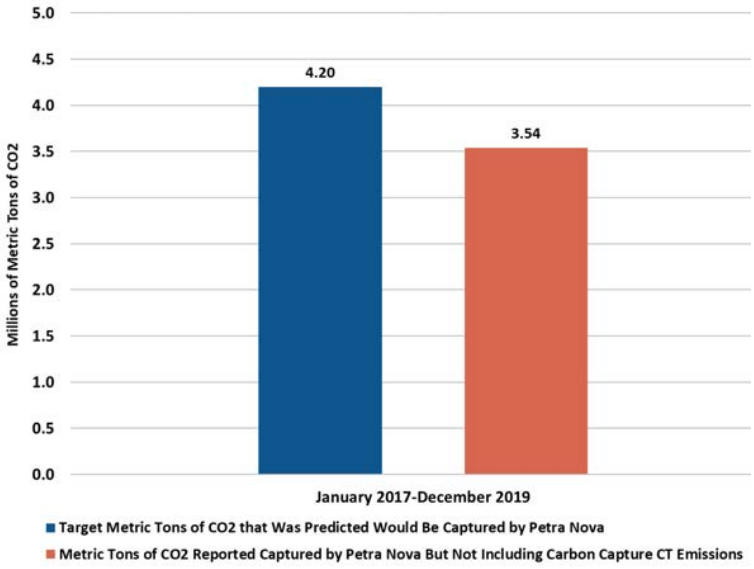
Petra Nova had reportedly suffered frequent outages and missed its carbon sequestration goal by 17%.

The plant was originally expected to capture at least 1.4 million metric tons of CO_2 annually (33% of carbon emission from unit 8 of the powerplant), or a total of 4.2 million metric tons from 2017 to 2019.[107, 108] However, as Figure 15 shows, the project fell well short of that goal during its first three years of operation. IEEFA estimated that the shortfall of 662,000 fewer tonnes in CO_2 captured would have cost investors about US$23 million. It was supposed to recover investment costs via.

[103] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[104] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[105] NRG. Petra Nova Status Update. August 2020.
[106] Reuters, Problems plagued U.S. CO_2 capture project before shutdown: document. August 2020.
[107] U.S. Energy Information Administration (EIA). Petra Nova is one of two carbon capture and sequestration power plants in the world. October 2017.
[108] U.S. Department of Energy, Office of Scientific and Technical Information (OSTI). W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project, Final Public Design Report. February 2017.

If the 20-year prospective lifetime of the plant is considered,[109] the cost to investors would have been at least US$150 million.[110]

Figure 15: Projected vs Actual Amount of CO_2 Captured by Petra Nova CCS Plant



Source: U.S. Department of Energy, NRG, Inc.

Moreover, the net amount of CO_2 reduction by Petra Nova would be less than the cited 3.54MT as the plant's built-in gas turbine had emitted about 1.1MT of CO_2 by May 2020.

The Petra Nova CCS project met neither the investors' financial expectations nor the specified CO_2 capture, the pre-assumed high-capacity factor of the power plant or the expected EOR rates. Over the past four years, according to company financial reports, NRG recorded three separate impairment charges related to the plant and to Petra Nova Parish Holdings, the subsidiary that operates the facility. The impairments have totalled US$310 million.

Paradoxically, these projects needed the power plant to produce more CO_2 to sell to oil companies and make money. So, they need an unrealistically high capacity factor to run and generate electricity. While research shows the capacity factor for fossil-based power plant is declining around the world.[111]

[109] Considering the full 20 years of operation for the plant is not a plausible assumption as it is highly correlated with oil price fluctuations, which practically shut down the plant just after three years. As the future unfolds a business model heavily reliant on a highly volatile oil price would not seem to be prosperous.
[110] Dennis Wamsted, David Schlissel. IEEFA. Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign. August 2020.
[111] Bruce Robertson, Milad Mousavian. IEEFA. Australia's Gas-fired Recovery Under Scrutiny Inaccurate Assumptions Behind Fossil Fuel Power Plants' Capacity Factor Leads to Financial Overvaluations. June 2021.

Based on the IEA Clean Coal centre report on CCS project costs published in 2020, the levelised cost of capturing CO_2 in Petra Nova was about $60–$70 per tonne. The real levelised cost would be much higher, however, as this study assumes an unrealistically high capacity factor of 85% for the plant.[112] Historical operation data shows the capacity factor of the plant to be about 63%.[113] The financial viability of similar projects, when sensitivity of cash flow is added to oil price fluctuations, must be questioned.

The validity of such projects, which use CO_2 to produce yet more fossil fuel, also must be challenged.

Boundary Dam

The Only Post-combustion CCS Plant in the World

The Boundary Dam Integrated Carbon Capture and Storage project was retrofitted to the lignite-fired Unit 3 of the 50-year-old Boundary Dam power plant in Saskatchewan, Canada. It was recognised as the first coal-fired power plant to use post-consumption CCS technology.[114]

Commissioned in October 2014, it is now the only operating coal-fired power plant in the world that captures CO_2. This project was re-sized from an earlier plan to build a 300MW clean coal facility, shelved by the previous provincial government because of its escalating cost (from US$1.5 billion to US$3.8 billion).

This smaller-scale project was initiated after the Canadian government gave the province C$240 million. It could capture CO_2 using post-consumption amine technology but also was equipped with facilities to capture sulphur dioxide and nitrogen oxides.[115]

Economics and Performance

The original estimated construction cost of the Boundary Dam project was US$1.3 billion but the ultimate figure was US$1.5 billion. Of the original estimate, US$800 million was for the CCS process, with the balance for retrofit costs.

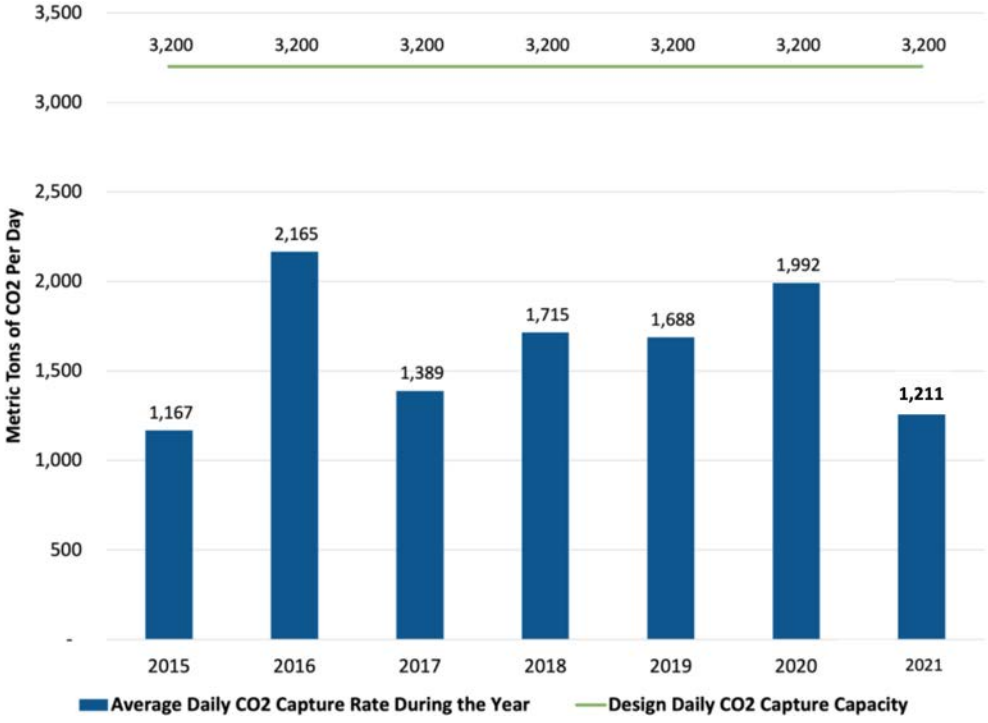
Besides selling electricity, the main revenue stream came from the contract with Cenovus Energy of Calgary, which were supposed to purchase the majority volume of 1Mtpa of captured CO_2 for EOR projects operated by Cenovus near the Weyburn oil field. While a majority of the 1Mtpa of CO_2 captured from Boundary Dam Unit 3 is expected to be sold for EOR operations at the Weyburn oil field, Aquistore provides a

[112] International Centre for Sustainable Carbon, Carbon Capture Utilisation and Storage – Status Barriers and Potential, CCC/304. July 2020.
[113] David Schlissel, IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[114] The Globe and Mail, Energy and Resources. SaskPower unveils world's first carbon capture coal plant. October 2014.
[115] IEAGHG. Integrated Carbon Capture and Storage Project at Saskpower's Boundary Dam Power Station. August 2015.

facility for "buffer" storage against EOR sales fluctuations.[116] Cenovus also set up injection wells and built a 60km-plus pipeline connecting the Weyburn EOR project to Boundary Dam.[117]

The initial goal of the project was capturing about 1 million metric tons of CO_2 each year or 3200 tonnes daily. However, the plant has captured an average of slightly more than 615,000 metric tons annually. Data published by SaskPower, the operator of the project, suggests that the Boundary Dam 3's average CO_2 capture rate to date is about 50%, not the targeted 90%.[118] It has barely achieved the latter figure on any single day and has never done so over any extended period.[119] Despite SaskPower's announcement regarding improvements and upgrading facilities during plant outages, as Figure 16 shows, the plant still falls well short of the original daily goal.[120]

Figure 16: Projected vs Actual Boundary Dam CO_2 Daily Capture Rate



Source: SaskPower's Monthly Boundary Dam Status Updates

[116] Global CCS Institute. Aquistore: CO2 Storage at the World's First Integrated CCS Project – Project Summary Report. 2015.
[117] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[118] SaskPower. BD3 Status Update: March 2021.
[119] IEEFA. Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.
[120] SSRN. SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability. March 2021.

Consequently, it took until March 2021 for Boundary Dam 3 to capture 4 million metric tons of CO_2, a yield that should have been met more than two years earlier, in October 2018.

SaskPower had counted on sales of CO_2 at US$19 (C$25) a tonne for Cenovus Energy's Enhanced Oil Recovery project. Without such sales, SaskPower's income was down. And without the expected CO_2 volume, Cenovus Energy collected US$9 million (C$12 million) in payments under the penalty provisions in its CO_2 supply contract.[121] SaskPower also became embroiled in two separate legal disputes with contractors over payments.[122]

The levelised cost of capturing CO_2 in Boundary Dam 3 has been calculated at about $100–$120 per tonne. As with Petra Nova, the underlying assumption for this calculation is that the plant operates at 85% capacity factor—which does not match SaskPower's monthly operating reports. The $100–$120 figure could be considered as the lowest cost of capturing carbon for the lower bound of Boundary Dam 3's carbon capturing cost.[123]

This project, though still operating, is struggling to meet the pre-specified targets.

Kemper Coal Gasification CCS Plant

A Failure and the Most Expensive Power Plant Ever Built

Gas and electric utility Southern Company's Kemper facility was supposed to be a flagship "clean coal" project. Initially proposed in 2008, the greenfield project near Meridian, Mississippi, U.S., was pegged to cost less than US$3 billion and to be running in 2014. It did not unfold as envisioned. Not only was it delayed for more than three years and cost more than US$7 billion, but the company also cancelled the integrated gasification combined cycle (IGCC) and carbon capture portions of the project.

Kemper was designed as a first-of-a-kind plant with a system that produced gasified coal to be burned in a modified combined cycle gas power plant and a carbon capture system that would pull the CO_2 from the gasified coal pre-combustion.[124]

The gasification process and associated emissions controls were expected to produce marketable quantities of ammonia and sulphuric acid as well as the captured CO_2, which was slated for use in EOR.[125] The main argument in favour of the project was that the CO_2 capture would bring the plant's emissions down to levels comparable with conventional combined-cycle gas-fired generators.

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[121] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[122] RenewEconomy. The fallout from SaskPower's Boundary Dam CCS debacle. November 2015.
[123] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[124] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[125] U.S. Department of Energy. Southern Company – Kemper County, Mississippi.

Essentially, the Kemper gasification process turned the relatively straightforward operation of burning coal to boil the water, running the steam turbine and producing electricity into a complicated chemical process that strips gas from coal to be used in a combined cycle gas turbine (CCGT) accompanied by a steam boiler/generator that uses the heat created through the chemical syngas production for electricity production.[126] These complicated steps were essentially added to use the lignite coal extracted from the Mississippi mine, which has 4 billion tonnes of reserves. Lignite or so-called 'brown coal' is considered the most harmful type of coal for human health as its heat value relative to the amount of CO_2 and sulphur it releases is lower than all other grades of coal.[127]

Economics and Performance

Running Kemper's commercial scale on-site equipment, including coal gasification and carbon capture, was expected to consume 30% of the plant's 830MW gross output. A typical natural gas-fired plant consumes just 3–4% of its gross output to run internal equipment. The conventional combined-cycle gas units at Kemper came online in late 2013.[128]

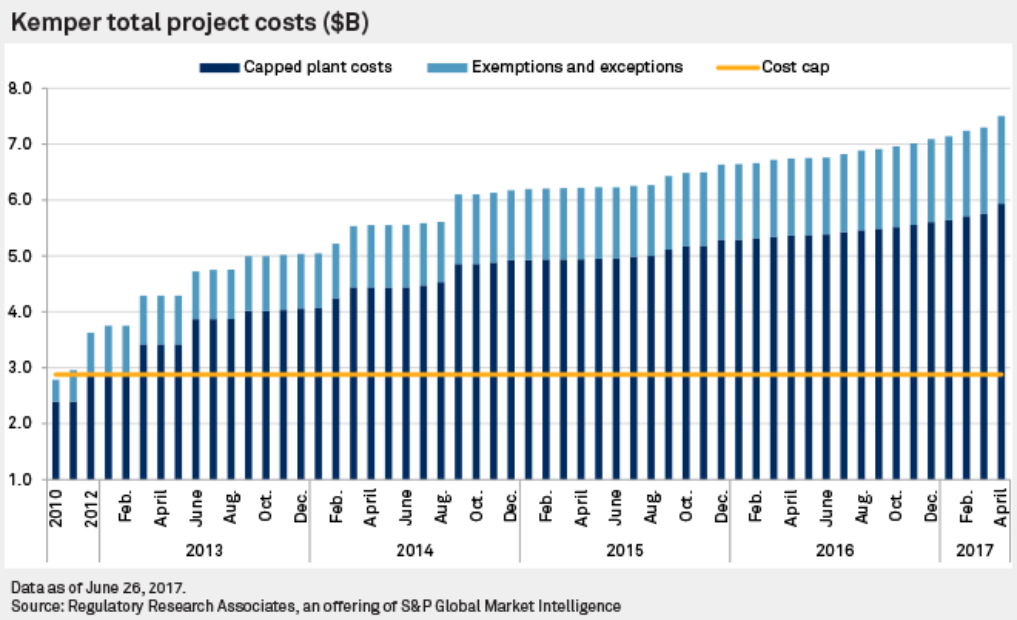
The Kemper project was approved in 2010 by the Mississippi Public Service Commission. Southern Company estimated the US$2.9 billion project would be in operation by the end of 2014. There was no reasonable estimate of either the cost or the commissioning date. Some consultants warned about cost underestimation at the time.[129]

Costs steadily increased as construction proceeded, as shown in Figure 17, and its commercial in-service date was repeatedly delayed. The "cost cap" represents that adopted by the Mississippi Public Service Commission, based on Southern Company's original cost estimate.[130]

Kemper began producing electricity in mid-2014 as a CCGT, burning natural gas, but problems with the operation of its unproven gasification systems—which were to have come online that same year—further added to costs and delays. These led to a 250% increase in the cost of the project, to US$7.5 billion.

[126] IEEE Spectrum. The Three Factors That Doomed Kemper County IGCC. June 2017.
[127] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[128] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[129] Mississippi Public Service Commission. Direct Testimony of David A. Schlissel on Behalf of the Sierra Club. December 2009.
[130] IEEFA. Costly and Unreliable, Two Multibillion-Dollar American Coal-Gasification Experiments Prove the Case Against Such Projects. September 2017.

Figure 17: Kemper IGCC Project's Increasing Cost (US$)



Source: SNL Financial, a unit of S&P Global Market Intelligence.

These technical and financial failures led to the Mississippi Public Service Commission calling for burning coal to cease and for gas to be used in CCGT. The commission said Kemper's gasification technology would not be used or useful in serving Mississippi customers. It found the technology had not operated reliably and was not likely do so in the near future.[131]

The Kemper "clean coal" journey ended in 2017 with the failed coal gasification idea. Southern Company was left with the then most expensive power plant ever built.[132]

Lessons Learned

Using CCS/CCUS in the power sector is the latest application of the technology, which has been gaining traction recently.

Despite generous funding and numerous incentives to push the technology in this sector (such as the 45Q Tax Credit in the U.S.[133]), it has shown a disappointing track record of failures, with a majority of the proposed CCS/CCUS capacity failing at the implementation stage or getting suspended early. Looking at the historical trajectory, technical issues have been one of the most prominent barriers. A lot of projects failed to operate at their theoretically designed capturing rates. As a result,

[131] Southern Company. Southern Company and Mississippi Power announce suspension of gasification operations at Kemper. June 2017.
[132] Bloomberg. Coal's Best Hope Rising with Costliest U.S. Power Plant. April 2014.
[133] Global CCS Institute. 45Q: The "Most Progressive CCS-Specific Incentive Globally" Is Now Open for Business. 24 March 2021.

the 90% emission reduction target generally claimed by the industry has been unreachable in practice.

There has not been any operational project that could meet its capture target so far. Petra Nova, marketed as a flagship breakthrough in this area, underperformed by 17% in four years of its operation before being mothballed indefinitely in 2020. Boundary Dam 3, the only active carbon capture project in the power sector worldwide, has captured less than its pre-specified target by a wide margin (about 50%).

The 90% emission reduction target generally claimed by the industry has been unreachable in practice.

CCS/CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced in the string of historical issues in retrofitting carbon capture technologies into power plants with several failed projects and cost blowouts.

The financial side of the CCS/CCUS business in the power sector is also problematic. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity that can go to consumers. It imposes additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

In a competitive electricity market, the high cost of CCS/CCUS will lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

The investment cost for such complex facilities is also staggering. This is evident in the case of the Kemper coal gasification plant that left investors with the most expensive power plant ever built at US$7.5 billion.

All in all, the technology should not be marketed as a quick fix for power sector emissions and make policymakers feel relieved about the world-saving technology just around the corner. It has not worked financially or technically. Instead, we should address the root of the problem, which is fossil-based energy production. Embedding carbon capture technologies in the proposed plan for building power plants and promoting such new fossil-based fleets in emerging economies such as Southeast Asia would have a deteriorating effect on climate in the long term.

Proven, cost-effective and climate-friendly alternatives reduce the dependency on fossil fuels and the risk of ending up with billions of dollars of stranded assets.



Section 4: Carbon Capture Application in Industry

The application of carbon capture in heavy industries and chemical production is diverse and complex.

It is not a monolithic subject: each application has its own specifications and considerations. It covers various technologies and processes, contrasting risks and opportunities, and differing mitigation potentials across multiple applications. Some domains in this sector need greater exploration, such as CCU, which is about utilising and recycling captured carbon into other valuable products such as cement and plasterboard blocks.[134]

In this section, we categorise the industrial application of carbon capture technologies into three categories:

1. Hydrogen production
2. Chemical production
3. Hard-to-abate industries

[134] Australian National University Reporter. Cementing future climate action. 2021.

Hydrogen Production

Hydrogen could play an important role in decarbonising industries, but what colour of hydrogen?

Different colours are used to differentiate hydrogen production methods. Grey hydrogen production utilises natural gas using steam reformation. It is an energy-intensive process that emits a lot of carbon dioxide. Blue hydrogen, often touted as a clean energy alternative, is essentially the same as grey hydrogen. The difference is that carbon dioxide emissions are captured during production using carbon capture technologies. And green hydrogen is made by electrolysing water into hydrogen and oxygen with renewable energy.

Green hydrogen is the real climate-friendly solution.

History shows that capturing more than 90% of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

Chemical production mainly comprises the production of fertilisers, ethanol, methanol and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. Results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the solution due to the financial and imminent cost-efficiency.

CCS/CCUS should not be an excuse to greenwash and encourage the establishment of new fossil-based fleets in different industries.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. These two industries constitute 13–14% of the total greenhouse gas emissions worldwide and are critical to decarbonising.[135] The only active CCUS project in this sector is in Abu Dhabi, United Arab Emirates. Although no official data on the performance or finance of the project are available, we reviewed this project based on different accessed sources that were publicly available. The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. However, as the carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem to be a sustainable solution.

Instead, alternative methods of steel production, such as scrap steel recycling, emit about 80% less CO_2 per tonne of crude steel than other forms of steel production

[135] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

used today. Green hydrogen leading to the production of "green steel"[136] also looks to be a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production green.

All in all, compared to the natural gas processing and power sectors, there are few sub-sectors in the industrial application where carbon capture could be considered as an interim option for decarbonisation while the research and development studies being done in parallel reach readiness and maturity levels to be commercialised. Even in these sub-sectors, such as cement, rigorous environmental and technical conditions need to be satisfied.

Blue hydrogen is not "clean" hydrogen.

Hydrogen could play an important role in decarbonising some energy-thirsty industries, whether for sectors that are hard to electrify or to address seasonal energy storages.

Some companies use CCS to promote the expansion of hydrogen made from natural gas. This type of hydrogen is typically labelled blue hydrogen as opposed to green hydrogen, which is produced with renewable energy.

Blue hydrogen is emissions intensive.

Blue hydrogen is an emissions-intensive process, even with CCS. It is also currently uncompetitive with its green cousin as global gas prices soar. Recent research from Cornell and Stanford Universities found that:

> *"Considering both the uncaptured carbon dioxide and the large emissions of unburned, so-called 'fugitive' methane emissions inherent in using natural gas, the carbon footprint to create blue hydrogen is more than 20% greater than burning either natural gas or coal directly for heat, or about 60% greater than using diesel oil for heat."*[137]

Researchers at the Australian National University came to similar conclusions in a recent scientific paper published in January 2022.

> *"We find that emissions from gas or coal-based hydrogen production systems could be substantial even with CCS, and the cost of CCS is higher than often assumed."*[138]

[136] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[137] Cornell Chronicle. Touted as clean, "blue" hydrogen may be worse than gas. August 2021.
[138] Science Direct. Clean Hydrogen? Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. January 2022.

Blue hydrogen is uneconomic in the face of high gas prices.

In addition, blue hydrogen seems to be no longer economic in the near future compared to green hydrogen. The gas market is global and very volatile. Prices can quickly fluctuate due to geopolitical issues, weather disruptions, supply and/or demand variations, etc. Blue hydrogen project economics are tied to this volatility. Expected production costs published only a year ago are significantly higher today, raising questions about continued policy support for the blue hydrogen technology. Unlike gas, renewables can be more regionally or locally located and are free from annual fuel cost dependency.

Green hydrogen projects can capitalise on this advantage and offer an alternative route to hydrogen production that generates near-zero emissions at a cost that could become cheaper than blue hydrogen no later than 2030. Although where possible, direct renewables use should be the alternative instead of producing green hydrogen.

Blue hydrogen's sensitivity to volatility in the gas market is alarming.[139] During 2021–2022, European gas prices have risen fivefold to more than €100/MWh, radically changing the cost dynamics for blue hydrogen. However, even with gas at €80/MWh, asset management company Alliance Bernstein has estimated blue hydrogen exceeds €6/kg.[140]

Blue hydrogen's sensitivity to volatility in the gas market is alarming.

Electrolyser costs are also falling fast. According to BloombergNEF's global head of strategy, Kobad Bhavnagri, green hydrogen's unit costs will be lower than US$2/kg by 2030 worldwide and US$1/kg by 2050.[141] Tenfold reduction in the cost of electrolysers and cheap renewable energy presents a "serious problem" for investments in blue hydrogen and will force gas companies to "think again", according to Bhavnagri.

[139] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[140] Reuters. Hydrogens civil war reveals its winner. 31 March 2022.
[141] Recharge News. 'White elephants' | Green hydrogen will be cheaper than blue H2 in all parts of world by 2030, says BNEF. 17 May 2022.

IEEFA has done extensive work on why blue hydrogen is not a climate solution from a technical, financial and environmental perspective.[142, 143, 144, 145, 146]

Case Studies

This section studies the following five important carbon capture projects in industrial applications: the Quest project is the project that has captured CO_2 more than any other CCS/CCUS project in the hydrogen production sub-sector; the Great Plains CCUS project is the largest and the oldest project in the chemical production (others) sub-sector producing Syngas; the Illinois Industrial CCS(IL-CCS), the largest and latest project commissioned in the ethanol production sub-sector; Coffeyville, the largest application of CCUS in the fertiliser production sub-sector; and Abu Dhabi CCUS is the only CCUS project operationalised in hard-to-abate industries worldwide.

These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications. IEEFA estimates that these five projects have captured 70–80% of all CO_2 captured by the industrial application of CCS/CCUS projects worldwide so far.

Quest CCS Project

The Athabasca Oil Sands Project, a joint venture between Shell Canada (60%), Chevron (20%) and Marathon Oil Sands L.P. (20%), proposed the development work in 2011 on a CCS project to help manage CO_2 from the Scotford Upgrader. This facility, near Fort Saskatchewan in Alberta, Canada, upgrades the extracted oil from the oil sands for refineries nearby. Shell started construction in September 2012 after receiving approval from Alberta's Energy Resources Conservation Board. The CCS plant was commissioned in August 2015 and reached commercial operation in Q4 of 2015.[147, 148]

Canadian Natural Resources Limited (CNRL) gained majority ownership of Quest in March 2017 as part of its C$12.7 billion acquisition of Shell's oil sands operations.[149] As of 2020, the Quest project ownership was 70% CNRL, 20% Chevron and 10% Shell.

[142] IEEFA. Blue Hydrogen Has Weak Case When It Comes to Emission Reductions. February 2022.
[143] IEEFA. Blue Hydrogen Has Extremely Limited Future in U.S. Energy Market. February 2022.
[144] IEEFA. Costs of Blue Hydrogen Production Too High Without Fiscal Life Support. February 2022.
[145] IEEFA. Reality Check on CO2 Emissions Capture at Hydrogen-From-Gas Plants. February 2022.
[146] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[147] Hydrocarbon Technology. Quest Carbon Capture and Storage Project, Alberta.
[148] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[149] Financial Post. Shell mulls more carbon capture projects in Alberta as Quest hits 5 million tonne milestone. 10 July 2020.

The Quest project targeted the capture of up to 1.2Mtpa (a proposed 27MT over the project life) of CO_2 from the Scotford Upgrader and aimed to permanently store it deep underground, reducing 35% of the CO_2 of the upgrader.[150, 151] The carbon dioxide is captured from the Scotford steam methane reformer units, which produce hydrogen for upgrading bitumen. The CO_2 is then transported about 65km by underground pipeline to an injection location near the Scotford Upgrader and stored at 2300 metres in a geological formation.[152] The project's engineering, procurement and construction was managed by Fluor Canada.[153]

The project delivered 1Mtpa in the first five years of operation,[154] on the way to an estimated 10.8MT for the first decade of operation. The storage capacity of the field has been reported at 27MT and the project life has been estimated at about 25 years.

Economics and Performance

Construction of the Quest project cost C$790 million and the total capital cost over 2009–2015 was C$1395 million. Of this, more than 40% (C$573 million) was funded by the Canadian and Alberta governments. A double CO_2 credit was also agreed, using a C$30/t[155] price to give the project C$60/t CO_2 reduction credits (and additional government funding of C$26/t). It adds C$1985 million of estimated project receipts from the Alberta and Canada governments until the end of the project's life.

On this basis, the total estimated government subsidies over the project's life is C$2.56 billion or C$95/t.[156]

[150] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[151] Global CCS Institute. Global Status of CCS 2020.
[152] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[153] Fluor. Shell Quest Carbon Capture and Storage.
[154] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[155] C$ per tonne of CO_2
[156] Quest Carbon Capture and Storage Project. Annual Summary Report – Alberta Department of Energy: 2017. March 2018.

Table 2: Financial Information of the Quest Carbon Capture and Storage Project

C$m	2009 Capex	2010 Capex	2011 Capex	2012 Capex	2013 Capex	2014 Capex	2015 Capex	2016 Opex	2017 Opex	2018-2025 Opex	2027-2040 Opex Etimated
Alberta Innovates	3	2	1								
Government of Canada				108			12				
Alberta Government				130	115	53	149	30	30	239	400
CO2 reduction credits *								3	36	466	781
Total Government Funding	3	2	1	238	115	53	161	33	66	704	1,182
Cummulative government funding	3	5	6	244	359	412	573	606	673	1,377	2,558
Cummulative government funding share	0.2%	0.4%	0.5%	17.5%	25.8%	29.6%	41.1%	43.2%	45.4%	62.5%	
Cummulative Capital Cost Implied	1,611	1,260	1,268	1,396	1,393	1,393	1,395	1,403	1,481	2,203	
CO2 stored (Mt) - actual or estimate							0.4	1.1	1.1	9.1	15.3
Cummulative CO2 stored (Mt)							0.4	1.5	2.6	11.7	27.0

* Double credits are received, valued at C$30/t * 2 = C$60/t

Total Capital Cost	1,395	C$m
Government subsidies	573	C$m
Cummulative government funding share	41.1%	

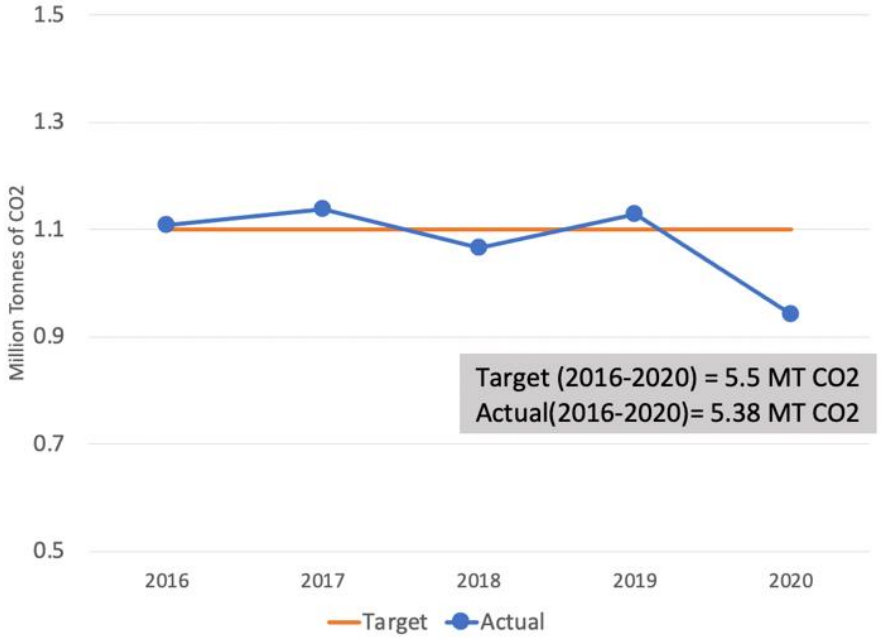
	2015-2025	2015-2040	
Capital Cost Total Subsidy	573	573	C$m
Operating Cost Total Subsidy	803	1,985	C$m
Total Subsdy	1,377	2,558	C$m
Expected CO2 captured	5.8	27.0	Mt
Subsidy per tonne	237	95	C$/t

Source: Shell Canada Energy, 2017 Annual Report

In terms of performance, Quest almost hit its yearly targets. The CCS plant was supposed to capture at least 1Mtpa and up to 1.2Mtpa. Taking the average of 1.1Mtpa as the target capture rate, to the end of 2020 it should have captured 5.5MT of CO_2. Based on the company's disclosures, the actual captured amount was 5.38MT; almost equal.

Figure 18 illustrates yearly amount captured and injected by the plant (orange line) versus the project's target (blue line). As depicted in the graph, the Quest plant largely performed at the targeted level until 2019. In 2020, the 15% drop in the injection rate reflects underperformance during the pandemic. However, the plant almost reached the overall pre-defined target after five years of operation.

Figure 18: Target vs Actual Capture Rate of Quest CCS Plant (2016–2020)



Source: Quest Annual Status Reports, IEEFA Analysis

The Real Amount of CO_2 "Avoided" Is Lower than What Was Just Captured

Limiting analysis to the cumulative amount of CO_2 captured by the plant is an incomplete conclusion about the performance of CCS plants as capturing operations produce additional CO_2 emissions.

The amount of CO_2 captured is not the net amount of CO_2 prevented from being emitted into the atmosphere. Any operation of the plant—such as absorbance, dehydration, compression, transport and injection—needs energy, the source of which is fossil fuel. That fuel and the fossil-based electricity used in each step produce CO_2 emission.

According to the Quest annual data, in the five years depicted in Figure 18 above, 1.16MT of CO_2 were emitted through the whole carbon capture and sequestration process (i.e., capture, transport and storage). So more than 21% of the 5.38MT of captured CO_2 was offset by the emitted CO_2.

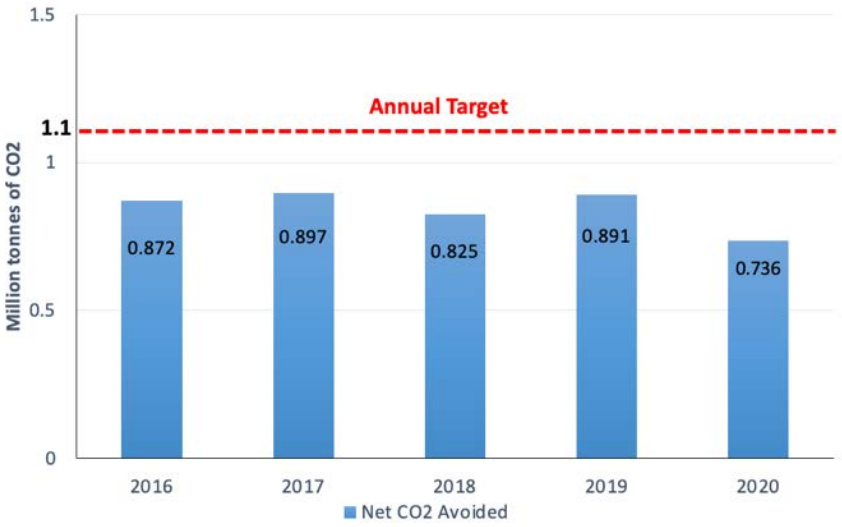
On this calculation, the net avoided CO_2 in the project's first five years was 4.22MT not 5.38MT. A similar calculation applies to each CCS plant that sources energy from fossil fuels. The 'net avoided CO_2' criterion reflects the real impact of CCS projects from an emissions reduction perspective.

Figure 19 compares the yearly amount of avoided CO_2 from the Scotford Upgrader with the target amount. For the Quest CCS operation, the net avoided amount did not exceed 0.9MT in any year, or only about 32% of the yearly CO_2 emission of the Upgrader and CCS plant together.

Extrapolating this trend and considering approximately 0.24MT of CO_2 emitted each year in capture, transport and storage indicate the CCS operation on its own would emit 6MT of CO_2 during the project's lifetime.

Accordingly, to the end of the project's life, the total amount of avoided CO_2 would be about 21MT instead of 27MT. Further, the government's subsidy per tonne of avoided CO_2 turns out to be C$120, considerably higher but more realistic than the C$95 figure.

Figure 19: Net CO_2 Avoided vs CO_2 Yearly Capture Target (2016–2020) – Includes Emissions from the CCS Operations



Source: Quest Annual Status Reports, IEEFA Analysis

Chemical Production (Ethanol, Fertiliser, Syngas etc.)

Chemical production could be the most convoluted application area for carbon capture technologies. This is because of the diversity of chemical products produced in this sector and of the technologies can be applied. It includes but is not limited to nitrogen-based fertilisers, such as ammonia and urea ammonium nitrate, ethanol and biofuel products, methanol, and reformed and synthetic gas. For many of the processes, blue hydrogen has been proposed. However, wherever hydrogen is applicable technically, green hydrogen would be the solution, not blue, due to the financial and emission reasons discussed earlier. For example, for nitrogen-based fertilisers, which need hydrogen to produce the final product, any type of coal gasification or petroleum coke gasification to produce hydrogen and then capture the released CO_2 with CCS facilities should not be greenlit. Instead, green hydrogen should be considered a climate-friendly alternative.

If there is no alternative to current processes in each of these applications, then carbon capture could be considered if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- liability of the projects is not handed over to the taxpayers.

In the following section, three of the biggest CCS/CCUS projects ever built in each sub-sector of chemical production have been reviewed. All of these projects are located in the U.S.: the Great Plains Synfuels Plant producing syngas from lignite coal gasification, which is planned to be redeveloped into a blue hydrogen project; the Illinois Industrial Carbon Capture and Storage, the largest project of its kind tied with biofuel production; and finally, the Coffeyville Gasification Plant, the biggest CCUS project in the fertiliser production sector.

Great Plains Synfuels Plant

The Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota, is a coal gasification plant that has produced synthetic natural gas (SNG) from lignite coal since 1984.

Coal gasification is a highly emitting process and lignite, also known as brown coal, used in this plant is considered the most harmful type of coal for human health due to the large amount of CO2 and sulphur it releases in combustion.[157]

Hence, the motivation behind such a heavily polluting project could be simply the abundance of cheap feedstock in the U.S. The National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE) estimates that about 200 years' worth of consumption remains in the U.S.[158]

Operated by the Dakota Gasification Company's (DGC), the GPSP is the only coal-to-SNG gasification plant in operation in the U.S. Annually, the plant consumes about 6MT of coal to produce 54 billion standard cubic feet of SNG as well as some chemical by-products.[159] The SNG (95% methane) is piped to the Northern Border Pipeline, which transports gas from Canada, Montana, and North Dakota to the Ventura, Iowa area, where it connects with numerous pipelines that supply the eastern U.S.

[157] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[158] National Energy Technology Library, U.S. Department of Energy. Hydrogen & Synthetic Natural Gas from Coal.
[159] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.

After 16 years of operation and venting millions of tonnes of CO2, capturing and selling of CO2 to the nearby oil producers started in October 2000. The CO2 is pumped via an onshore 315km pipeline for EOR in two carbonate fields, the Cenovus Energy-owned Weyburn field (with demand rate of 6500 tonnes per day) and Apache company-owned Midale field (with demand rate of 1200 tonnes per day).[160]

CO_2 Leakage Case

Following claims of leakage from the Weyburn site in January 2011, operator Cenovus and the International Performance Assessment Centre for Geologic Storage of CO_2 (IPAC-CO_2) launched investigations. The "leaking" gas was discovered to be naturally occurring biogenic CO_2, originating from biological processes in the soil, rather than injected CO_2. The 2012 report discovered no potential CO_2 pathways from pipelines or other infrastructure.[161]

Economics and Performance

GPSP was commissioned by American Natural Resources company (ANR). However, as it was not easy to secure financing for such a huge project, ANR formed a partnership with several other natural gas utility companies which became known as the Great Plains Gasification Associates (GPGA). This allowed the U.S. DOE to back funding for the plant.[162]

The plant was built in response to the energy crisis of the 1970s.[163] Total cost for design and construction was roughly U$2 billion of which a $1.5 billion loan was guaranteed by the DOE.[164] Construction began in 1981.[165]

In addition, the CO_2 monitoring and storage project in Weyburn and Midale fields was conducted between 2000 and 2011 (at an estimated cost of U$70 million).[166] And the cost of pipeline was US$100 million.[167]

According to the DOE's NETL, the separated CO_2 was emitted into the atmosphere for the first 16 years of the project's lifetime due to lack of demand. In October 2000, the operator started capturing and selling CO_2 to oil companies for EOR in the nearby fields. The capacity at the beginning of the project was reported to be about 105 million standard cubic feet per day (~2Mtpa) or 60% of total CO_2 produced by the plant.[168] This

[160] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[161] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[162] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[163] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[164] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[165] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[166] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[167] School of GeoSciences, University of Edinburg. Great Plains Synfuels Plant: Project Details.
[168] National Energy Technology Library, U.S. Department of Energy. Weyburn Project. n

capacity increased to about 3Mtpa in 2006 by installing the third CO_2 compressor to meet the needs of Apache Canada Ltd for EOR. Up to 2007, CO_2 sales exceeded 11MT.[169]

For the first six years of operation the carbon capture facility averaged 1.8–1.9Mtpa, very close to its nominal capture capacity.

No detailed data and information have been found regarding the plant's annual capture performance. Based on cumulative figures from the MIT CCS database[170] and National Petroleum Council report,[171] it had captured and transported nearly 38MT of CO_2 for geological sequestration up to 2020. Factoring in the capacity expansion to 3Mtpa in 2006, the total amount CO_2 captured and sold for EOR until 2020 was 27MT.

The average annual capture rate for the 14 years post-expansion has remained ~1.9 Mtpa, or about 1MT lower than the maximum capture capacity for these years.

The first hypothesis is that this underperformance could be due to lower gas production in the main synthetic gas production plant. Should this be the case, the CCS plant would not be underperforming. On the other hand, the alternative hypothesis is that CCS plant underperformance, technical problems or lack of demand from oil companies would result in the uncaptured CO_2 being vented into the air.

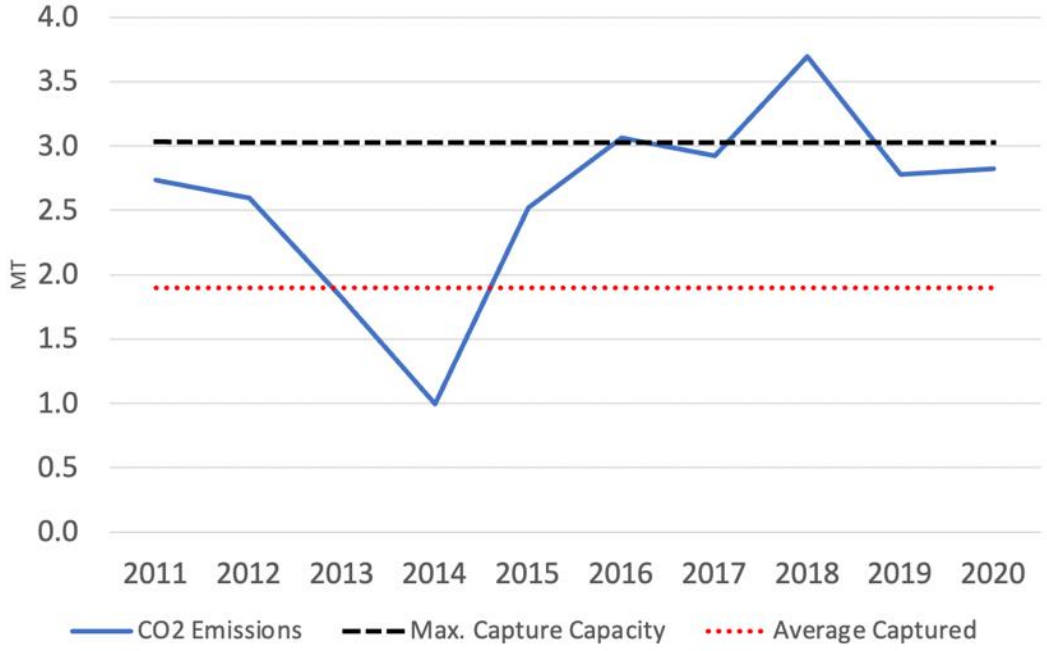
Looking at the U.S. Environmental Protection Agency (EPA) data of the plant's CO_2 emissions for the period 2011–2020 confirms the underperformance hypothesis.

Figure 20 shows the CO_2 emissions from the synthetic gas (syngas) production process (blue line), maximum capture capacity of the plant (black dotted line) and the average yearly captured CO_2 of the plant (red dotted line).

It essentially shows that during this decade the amount of CO_2 produced by the plant was higher than the average 2MT capture rate (2014 excepted). The CCS facility had the capacity to capture all of the CO_2 produced by the syngas process (but for 2018, when CO_2 production exceeded the maximum 3MT capturing capacity).

[169] National Energy Technology Library, U.S. Department of Energy. Weyburn Project.
[170] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[171] National Petroleum Council. Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage. Appendix C – CCUS Project Summaries. December 2019 (last updated 12 March 2021).

Figure 20: Great Plains Synfuels Plant CO2 Emissions vs Capture Performance (2011–2020)



Source: National Energy Technology Laboratory (NETL), Department of Energy. U.S. Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP). IEEFA

The cumulative tallies for CO_2 captured and produced during 2011–2020 show that the CCS plant underperforms by about 25%. During the decade, it captured about 19MT of CO_2 to be sold for producing more oil and vented another 6–7MT. (Figure 21).

It is important to note that the overall figure for emitted CO_2 should be considerably higher as the above figures exclude the emissions from the CCS facility operations, potential leaks through pipelines and fixtures and the CO_2 emitted in reinjecting at the EOR point.

An Imminent Blue Hydrogen Redevelopment for Plant

In 2021, Bakken Energy and Mitsubishi Power Americas announced plans to purchase GPSP from Dakota Gasification Co., which is financially in trouble. The deal was expected to be finalised by April 2022.[172] It is part of a plan to create a hydrogen hub in Dakota.[173] It has been labelled "clean" hydrogen. However, the hub will focus on the production of blue hydrogen, derived from natural gas with CO_2 emissions captured, and sequestered underground or used for EOR. The hydrogen will come

[172] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[173] AP. Companies aim to build 'clean hydrogen' hub in North Dakota. 3 June 2021.

from natural gas produced in North Dakota's oil fields or from gas from the Dakota Gasification plant, or a mix of both.

The hub is not a green hydrogen project as it is essentially producing gasified hydrogen and capturing its CO_2 by-product. Blue hydrogen is neither a climate-friendly solution or an economically sound choice compared to green hydrogen, as discussed earlier.

Illinois Industrial Carbon Capture and Storage (IL-CCS)

In 2011, Archer Daniels Midland (ADM), one of the world's largest agribusiness companies, started the Decatur carbon capture project with partners. As part of the U.S. DOE's Regional Carbon Sequestration Partnerships initiative, and with funding from the DOE, it started as a research and development project in industrial CCS, in Illinois.

Having passed pre-specified targets for capturing carbon and showing no CO_2 leakage, the project moved ahead to the design and implementation phases and captured and stored 1MT of CO_2 from 2011 to 2014.[174]

With the successful completion of the Decatur demonstration project, ADM and corporate partner Schlumberger Carbon Services continued on to the larger- scale Illinois Industrial Carbon Capture and Storage (IL-CCS) plant with a 1Mtpa capturing and storing capacity. Started in 2017, as the world's first large-scale CCS project from a biofuel source, it relied on the Mount Simon Sandstone saline formation as its dedicated geological structure to store the captured carbon. The CO_2 not being used for EOR was to be stored more than 2000 metres underground.[175]

The gas from the ADM biofuel plant is a >99% pure CO_2 stream that is a by-product of fuel-grade ethanol production via anaerobic fermentation of corn stover (harvest remnants).[176]

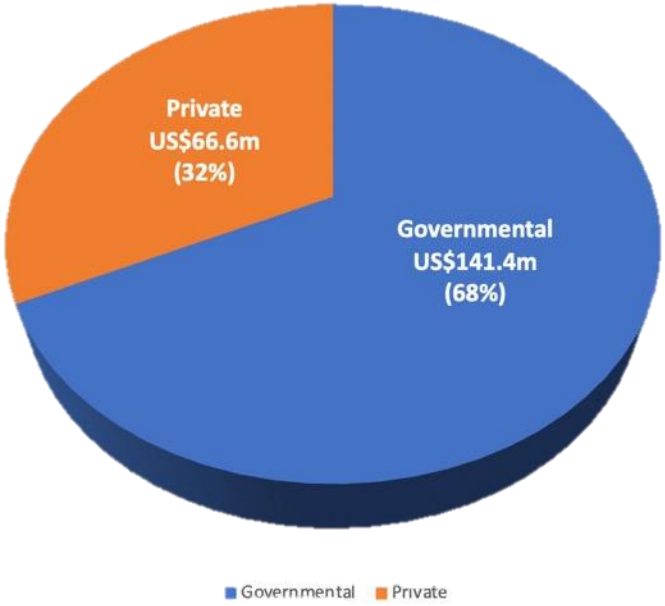
Economics and Performance

Following the success of the Decatur project, backed by about US$106 million in federal funding and US$21 million from the corporate partners, site characterisation and permitting of IL-CCS was finished in 2014 and the project started to capture and inject CO_2 in 2017.

[174] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[175] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[176] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.

The cost of the project was US$208 million, of which US$141.4 million came via the DOE's CCS grants. Essentially, the project was 68% government funded (Figure 21).[177, 178, 179]

Figure 21: IL-CCS Finance Portfolio



Source: U.S. Spending.gov.

Looking at total CO_2 emissions of the ADM biofuel plant, the figure is four to five times higher than the designed capture target of 1Mtpa. On average, the plant has emitted 4.5MT of CO_2 annually. In the best-case scenario, if the CCS facility could capture at its theoretical capacity, it would contain only 22% of the plant's CO_2 emissions. This illustrates how technically and economically challenging it is to reach capture rates of >80% that are usually claimed for CCS facilities. The technical difficulty is evident in the quote by engineering consultancy WSP, advisor to ADM for a carbon reduction feasibility study in 2020:

> *"The ability to capture stack emissions and sequester them is likely 10 years out, due to the technology and energy needed to separate and process the stack gas sufficiently to inject the CO_2 in the sequestration well."*[180]

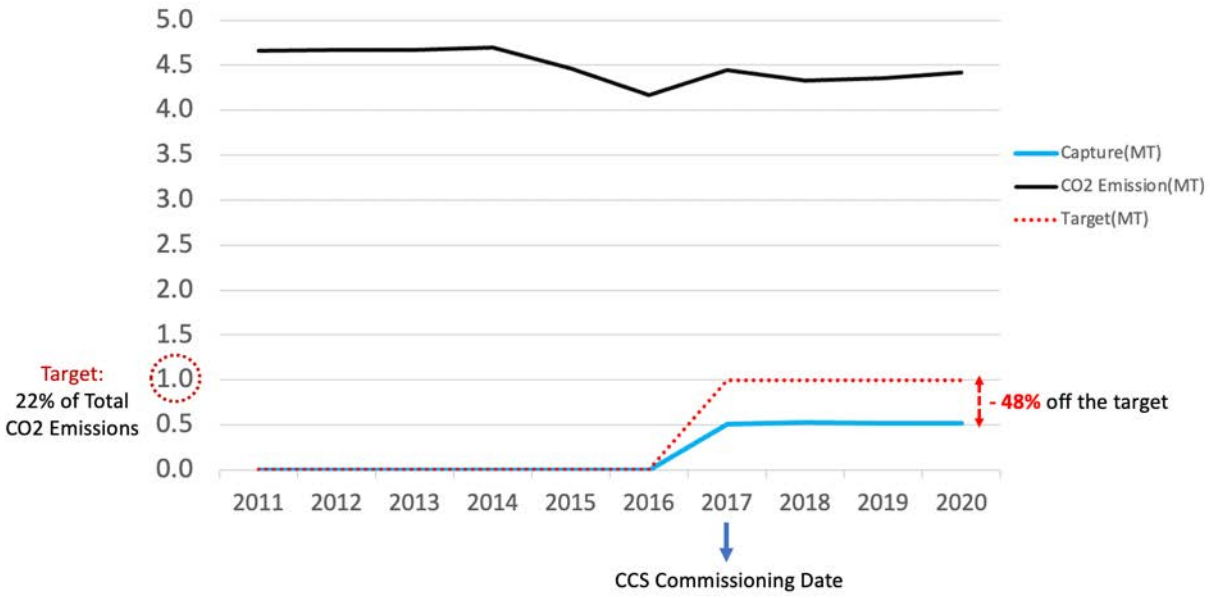
Moving from theory to practice, the reality is even starker. EPA data illustrate that the CCS facility has been performing at about half of its designed capacity since the beginning of the project (Figure 22).

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[177] Midwest Center for Investigative Reporting. Despite hundreds of millions in tax dollars, ADM's carbon capture program still hasn't met promised goals. 19 November 2020.
[178] USASpending.gov.
[179] AIChE Academy. Successful Demonstration of Illinois Industrial Carbon Capture and Storage in a Saline Reservoir. 2018.
[180] Archer Daniels Midlands. Carbon Reduction Feasibility Study. 30 March 2020.

The facility is underperforming by 48% to the end of 2020,[181] meaning that it could capture and sequester only up to 12% of the total CO_2 emissions of the ADM biofuel plant. The emission problem is still there and, essentially, the US$200m-plus CCS retrofit could not solve that.

Figure 22: CO_2 Emissions vs Capture Performance of the IL-CCS Plant (2011–2020)



Source: Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP).

Coffeyville Resources Nitrogen Fertilizers Plant

Coffeyville Resources Nitrogen Fertilizers Plant incorporated in 2003[182] in Kansas, U.S., produces ammonia and urea ammonium nitrate (UAN) fertilisers. It gasifies petroleum coke to produce hydrogen, from which it synthesises ammonia and UAN fertilisers. An oxygen separation plant provides oxygen for the gasifiers, as well as nitrogen needed downstream for reaction with hydrogen to produce ammonia. Syngas is cleaned in a dual-stage acid gas removal process, delivering Hydrogen sulfide (H_2S) and CO_2 in separate streams.

A proportion of the separated CO_2 is used to produce UAN but most of the gas was vented in the first decade of the plant's operation.

[181] The data was accessible through until end of 2020.
[182] Bloomberg. Coffeyville Resources Nitrogen Fertilizers.

The plant produces about 5% of total UAN demand in the U.S. and is close to extensive fertiliser markets in the Midwest, lowering the distribution costs of its products.

In 2011, subsidiaries of Chaparral Energy and CVR Energy (the owner and operator of the Coffeyville plant) reached a purchase and sale agreement to capture CO_2 from the plant, which Chaparral needed for EOR operations in north-eastern Oklahoma. The plant started to capture CO_2 in June 2013. Under the agreement, the majority of the plant's CO_2 was planned to be captured by Chaparral, which constructed a CO_2 compression facility at the plant site and installed about 110km of pipeline to deliver it to its North Burbank Unit in Osage County in Oklahoma.[183]

Economics and Performance

Blue Source, LLC, a carbon-reduction advisory company, initiated the idea of capturing greenhouse gas from the fertiliser plant and injecting it into ageing petroleum fields to boost oil output. With Chaparral Energy and CVR Energy, it planned and executed the CCS retrofitting and construction of the pipeline. The project was estimated to cost between US$50 million and US$$80 million.[184] The project was finished, and injection started in 2013.[185]

U.S. EPA data for total CO_2 produced by the fertiliser plant is shown in Figure 23 (orange line). However, as a step in the UAN production process, part of the CO_2 produced during the acid gas removal process is then used in production of UAN. Hence, the net emitted CO_2 is lower than the total CO_2 produced. Based on industry averages[186] and scattered data publicly available on the facility's UAN production figures,[187] the average CO_2 produced (excluding the amount used in UAN production) is an estimate (blue line).

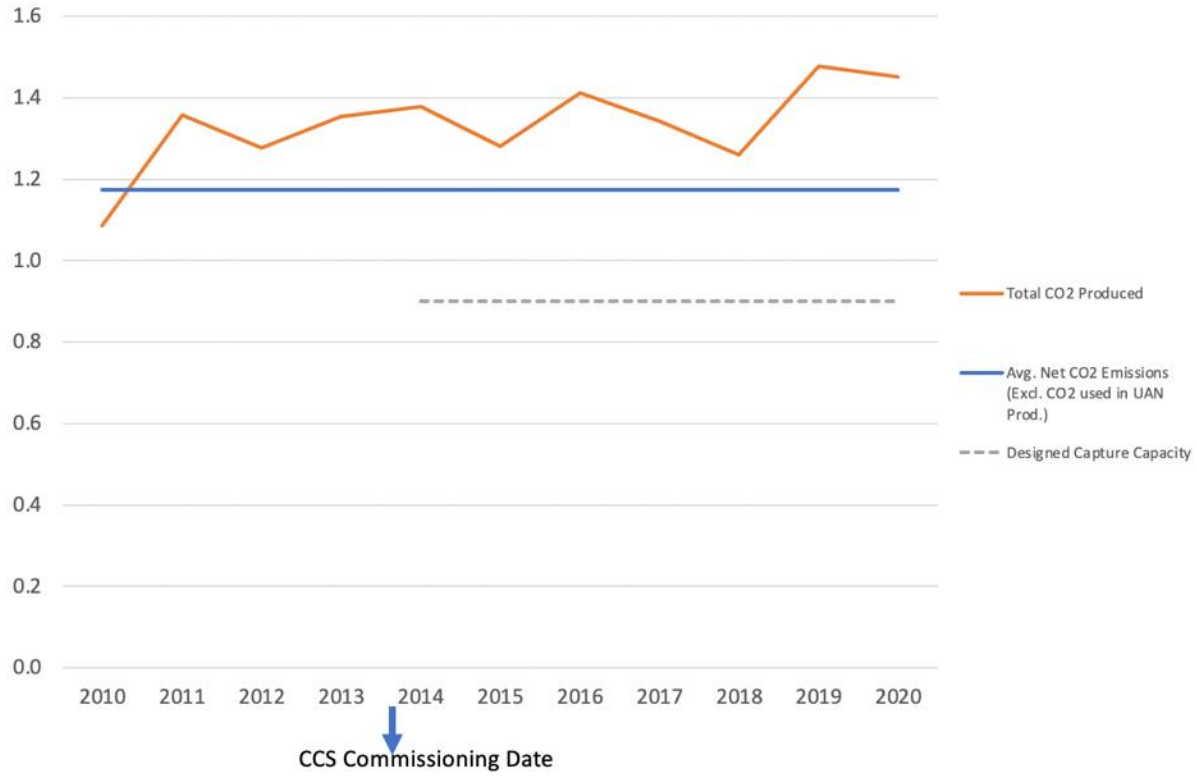
No public data has been found on the yearly capture performance of the plant over its whole lifetime. For illustration, the maximum capture capacity of the plant (Figure 23, grey dotted line) accounts for up to 80% of its CO_2 emissions. Some research shows that the plant could have overperformed during 2017–2019 by about 16%, which is an acceptable result.[188] However, the question remains as to whether the plant has achieved maximum capacity each and every year since 2013, given very few CCS/CCUS projects have done so historically. Also, it is notwithstanding that captured CO_2, when used for EOR, at least partly negates the original figure of reduced carbon.

As most of the CO_2 created in these plants assist in the production of hydrogen to be used in fertiliser production, replacing green hydrogen with current processes of producing syngas hydrogen from petroleum coke seems to be more efficient and climate friendly than the technically challenging and extremely expensive carbon

[183] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[184] Reuters. Blue Source to capture Kansas CO2, up oil output. 21 August 2007.
[185] ZeroCO2.no. Coffeyville Gasification Plant.
[186] International Fertiliser Society. The Carbon Footprint of Fertiliser Production: Regional Reference Values. 2019.
[187] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[188] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

capture solutions. Considering the falling cost of green hydrogen and recent astronomical gas prices, it would soon also be a more economical option compared to blue hydrogen.

Figure 23: Coffeyville CCS CO_2 Emissions vs Maximum Capturing Capacity (2010–2020)



Source: MIT. CCS database. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program(GHGRP). International Fertilizer Society(IFS), 2018.

Hard-to-abate Industries (Steel and Cement)

Source of ~14% of Global CO_2 Emissions

Steel and cement are named hard-to-abate industries as it is technically and financially difficult to completely electrify them using renewable energy. Yet, according to Imperial College London, cement and steel production contribute to 6.5% (2.3 billion tonnes) and 7% (2.6 billion tonnes) of global CO_2 emissions, respectively.[189] That is partly owing to the large quantities of use of these materials: concrete is the second-most-consumed product on the planet, after clean water. It is also due to their carbon-intensive manufacturing: the chemical reactions and the burning of fossil fuels to deliver the extreme temperatures required all release CO_2.

[189] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

Carbon capture has been discussed recently as one of the solutions contributing to decarbonising these heavy polluting industries.

There is only one operating CCUS plant in the steel sector and no commercialised CCS plant in the cement industry.

There is no public data on the performance and finance of the only operating CCUS project in Abu Dhabi, United Arab Emirates. Hence, there is not much to learn from the history of the application of CCS/CCUS in this industry. However, the technical failures of CCS/CCUS in other sectors are alarming. This is important as the time to reach net zero targets is very limited, and there is little room for trial and error. Nevertheless, there is a lot of research and development going on to decarbonise these two industries with different options[190, 191] and CCS/CCUS has been considered as one of the alternatives.

There is only one operating CCUS plant in the steel sector.

Steel

There are three main steel production processes.

1. The most widespread is the integrated blast furnace and basic oxygen furnace process (BF-BOF), in which iron oxide is reduced to iron inside the blast furnace with coke (derived from coking coal) as a reducing agent. The product of the blast furnace, carbon-rich pig iron, is then processed into steel in a basic oxygen furnace, where oxygen is blown through the molten pig iron to reduce its carbon content. In 2020, global crude steel production totalled 1.88 billion tonnes, and of this, 73% came via the BF-BOF process.[192]

2. A second primary steelmaking pathway is to produce direct-reduced iron (DRI), which is then further processed into steel in an electric arc furnace (EAF). DRI is produced by directly reducing iron ore without melting, usually using a mixture of carbon monoxide and hydrogen derived from natural gas. Although, these can also come from gasified coal. This method provides the final steel product with around 36% less CO_2 emissions.[193]

[190] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.
[191] IEEFA. Green steelmaking will need technology and mining advances. 1 July 2022.
[192] World Steel Association. World Steel in Figures 2021 now available. 3 June 2021.
[193] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.

DRI does not use coking coal. An increasing number of steel companies are seeking to develop technology that uses 100% hydrogen in the DRI-EAF process—potentially zero-carbon green hydrogen, produced via renewable energy-powered electrolysis.[194] And due to the reasons discussed earlier, green hydrogen is the fuel for heavy industries' future. Any type of coal gasification/methane reformation to produce hydrogen and then capturing its carbon with CCS/CCUS—that is, blue hydrogen—does not seem to be a climate saviour or cost-efficient option.

3. As an alternative to primary steel manufacture, recycling scrap steel is an option with around 80% lower CO_2 emissions.[195] Also called secondary steelmaking, this technology does not require iron ore or coking coal. An electric arc furnace is charged with steel scrap, which is melted to form new steel. Renewable energy can power EAFs, reducing carbon emissions for the scrap EAF process to almost zero. Although there are limitations on the volume of available scrap and some quality issues, even a little increase in this type of production instead of BF-BOF would be a gamechanger.

Although there is a long way to go in the steel sector, green hydrogen seems to be a more promising pathway than CCS. As discussed, it will be a cost-effective option in the next few years.

The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. But, as carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem a sustainable solution.

Green hydrogen seems to be a more promising pathway than CCS.

Instead, alternatives such as scrap steel recycling or green hydrogen leading to the production of "green steel"[196] looks a more promising path to follow.

Cement

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. The process is known as calcination when crushed limestone is heated and releases calcium oxide (CaO) and CO_2.[197]

$$CaCO_3 + heat \rightarrow CaO + CO_2$$

[194] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.
[195] IEEFA. The facts about steelmaking: Steelmakers seeking Green Steel. 2022.
[196] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[197] University of Mosul. Calcination of Limestone.

The heat for the process and the chemical reaction itself produce CO_2.

Second only to water, concrete is the most consumed material in the world.[198] Considering these two facts, it is one of the most challenging industries to decarbonise.

Carbon capture technologies seem to be useful in this industry if they are not used as an excuse to postpone other methods now under investigation to reinvent processes and make cement production green.

For example, one of the recent innovations in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[199] These processes are worth being funded and studied.

Abu Dhabi CCUS Plant (Al Reyadah)

The First and Only CCUS Plant in the Steel Sector

The Abu Dhabi CCUS plant, commissioned in 2016 in Mussafah, Abu Dhabi, United Arab Emirates, is the only commercial-scale CCUS facility in the world that captures CO_2 from the flue gas of a steel production facility. The final application of the captured CO_2 is EOR in the Abu Dhabi National Oil Company's (ADNOC) nearby oil fields.[200]

The main objectives of the project were reducing the carbon footprint of the United Arab Emirates, implementing EOR in subsurface oil reservoirs, and freeing up natural gas that would have been used for oil field pressure maintenance.[201] From the emissions perspective, such objectives seem incompatible with climate targets, as the CO_2 is used to increase oil production and free up other emission-intensive fossil fuels.

Economics and Performance

The project cost was US$122 million,[202] and it was developed by Abu Dhabi carbon capture company Al Reyadah, a joint venture between ADNOC and clean energy company Masdar,[203] with respective stakes initially of 51% and 49%. ADNOC bought out Masdar's share in January 2018.[204]

[198] Engineering Failure Analysis. Cement and concrete as an engineering material: An historic appraisal and case study analysis. 2014.
[199] Australian National University Reporter. Cementing future climate action. 2021.
[200] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details.
[201] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[202] The National News, Business. Abu Dhabi starts up world's first commercial steel carbon capture project. 5 November 2016.
[203] Power Engineering International. MENA's first CCUS project now operational. 6 January 2017.
[204] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details. 2022.

The project includes capturing, compressing and dehydrating the CO_2 and then conveying it via a 43km underground pipeline for EOR injection to ADNOC's North East Bab (NEB) (Al Rumaitha) and Bab onshore oilfields.

The project was set to capture and transport 800,000 tonnes per year of CO_2 and, tentatively, was part of an overall master plan to create a CO_2 network and hub for managing future CO_2 supply and injection requirements in the United Arab Emirates.[205]

Technically, the plant is the largest CO_2 project of any type in the Persian Gulf region,[206] the Middle East's first commercial-scale CO_2 capture plant and the project with the world's highest pressure (240 bar) CO_2 transfer pipeline at the time of commissioning. ADNOC has announced plans to expand the capacity of this program by more than 500%, aiming for 5MT of CO_2 annually by 2030.[207]

Phase 2 of the project, set for commissioning in 2025,[208] aims to capture 1.9 to 2.3Mtpa CO_2 from its gas processing plant for EOR in the same reservoir. At the same time, the company plans to increase production to 5 million barrels of oil equivalent (boe) daily in 2030.[209]

The CO_2 to be captured by CCS plant(s) would have a considerable contribution to expanding that production, raising the question yet again: Is using CCS for EOR really reducing emissions?

Lessons Learned

Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world wants to reach net-zero emissions by 2050. CCUS/CCS has been proposed as one of the pathways for pursuing the decarbonisation of these two industries.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications with common processes as these industries, as well as other solutions being developed and researched in parallel, future CCS/CCUS application in the steel and cement industry could be projected to some extent.

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[205] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[206] Global CCS Institute. Building Momentum for CCS in the Gulf Region and Around the Globe. 2020.
[207] Hydrocarbon Processing. ADNOC announces expansion of carbon capture program. February 2020.
[208] International Association of the Oil and Gas Producers. Global CCUS Projects. 2021.
[209] Drilling Contractor, Increased hydrocarbon production, sustainability programs go hand in hand to create a resilient upstream. 27 April 2021.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, however, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green and zero-emissions cement.[210] For example, one recent innovation in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[211] Cambridge University researchers have proposed zero-emissions cement.[212] Both innovations are worth exploring.

Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS also should be used only if the technical performance reaches close to nominal capture capacities, in contrast with general trends throughout history. Also, it could be considered an interim option as long as it does not distract financial flows from fundamental and innovative solutions to reinventing the cement production process.

[210] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.
[211] Australian National University Reporter. Cementing future climate action. 2021.
[212] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.

Conclusion

Failed/Underperforming Projects Considerably Outnumbered Successful Experiences

The immediate inference from the projects reviewed is that the number of failures and the underperformance of these projects with carbon capture technology has outnumbered the successful projects considerably. Ten of the 13 flagship projects reviewed, comprising 90% of the total capture capacity in our sample, have failed or are underperforming mostly by large margins.

While a limited sample, predominantly focusing on projects in operation, additional research[213] looking (from a different angle) at the number of failures of all of the proposed/initiated projects since 2000 conveys, in essence, a similar message. Further, recently published research by the Imperial College London[214] on the capture performance of operating projects since 1996 confirms the underperformance of most projects against their designed/claimed capture capacity.

Successful CCUS Exceptions Mainly Existed in the Natural Gas Processing Sector Serving the Fossil Fuel Industry, Leading to Further Emissions

The natural gas processing sector historically dominates the application of carbon capture technology. Extracted raw gas has a carbon dioxide (CO_2) content that needs removal to produce a marketable (methane) gas for distribution through pipelines to customers or liquefied in LNG plants for export.

Producing the primary usable product (i.e., natural (methane) gas) is impossible without separating CO_2. This explains why the sector has been using carbon capture technology for decades, not necessarily as a climate-friendly solution, but as an inevitability to produce the fossil-fuel natural gas. On top of that, selling the captured CO_2 primarily to oil producers for enhanced oil recovery improves the economic viability of gas development projects. Sleipner and Snøhvit have two of the most successful among the few successful projects in the history of carbon capture being used in this sector.

The IEA's Net Zero by 2050 report, one of the seminal energy transition roadmap documents worldwide, has explicitly expressed alarm about the danger of developing any new oil and gas projects globally. It emphasised not developing any new oil and gas projects if the world wants to reach net zero by 2050.

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[213] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[214] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

The Elephant in the Room of the Application of CCS/CCUS in the Natural Gas Processing Sector: Scope 3 Emissions Are Still Not Being Accounted for

Gas processing CCS/CCUS covers a tiny proportion of the value chain of emissions compared to CCS/CCUS in other sectors. As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is not about reducing Scope 3 emissions from the final combustion/use of gas. Rather, it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels.

As such, giving the green light to new oil and gas projects just because of CCUS/CCS promises attached to those projects is not climate friendly. Even if the CCS/CCUS facilities work at their capacity (which has not been the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions of themselves by adding CCS/CCUS.

The gas burnt at the end of the value chain produces the most significant chunk of emissions.

The gas burnt at the end of the value chain produces the most significant chunk of emissions, which CCU/CCUS proposals do not address.

Captured Carbon Has Mostly Been Used for Enhanced Oil Recovery (EOR): Enhancing Oil Production Is Not a Climate Solution

Today, EOR is the only industrial use of CO_2 to have reached a considerable scale. In recent years, EOR projects have used about 73% of the CO_2 captured globally each year. This figure was greater in previous decades.

EOR enhances the oil production rate from fields that have passed the maximum output rate. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons. Oil producers can make money by revitalising oil fields with declining production rates.

EOR itself leads to CO_2 emissions. CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either is burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28MT out of 39MT total capture capacity, is reinjected and sequestered into oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.

IEEFA has estimated that the vast majority of the total captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Relatively speaking, carbon capture and storage with dedicated geological structures (CCS) is better than CCUS, which is essentially EOR. Any carbon capture project with the final goal of enhancing oil production would not be a climate solution, regardless of whether the carbon capture facility could reach its capture capacity.

Using Carbon Capture as a Greenlight to Extend the Life of Fossil Fuels Power Plants Is a Financial and Technical Risk: History Confirms this

CCS/CCUS for the power sector, one of the most recent proposed applications of carbon capture technology, is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream. This is evident by the string of historical issues in retrofitting CCS/CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2. While this may seem small in concentration, it is large in terms of absolute volume globally.

Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to the consumers. This also means that more fossil fuels will need to keep burning to generate the same amount of electricity in a non-CCUS power plant.

Capturing CO_2 consumes a lot of energy.

To compete in a competitive electricity market context, the high cost of CCS/CCUS will need compensation by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and could also lead to financial instability for the project or environmental externalities, especially in the case of using CO_2 for EOR. Government

incentives should instead flow into fast-growing, efficient, and clean renewable energy technologies and the battery and storage sectors.

Further, apart from the financial argument, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.

Some Applications of CCS in Industries Where Emissions Are Hard to Abate (Such as, Cement) Could be Studied as an Interim Partial Solution with Careful Consideration

Industrial applications of CCS are very diverse. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with the current high commodity prices, using green hydrogen is a better way to go rather than blue hydrogen.

History shows that capturing 90% (or more) of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

It is, however, worth studying carbon capture as an interim solution in some sectors, such as cement.

This report studies five flagship cases in different sub-sectors that account for about 65% of the total existing industrial carbon capture capacity. Chemical production mainly comprises the production of fertilisers, ethanol, methanol, and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. The results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed for blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the better solution due to the financial and imminent cost-efficiency.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world aims to reach net-zero emissions by 2050.

The steel sector is in the early years of utilising carbon capture technology. Studies could be done on probable projects. However, as carbon capture technology in different sectors has *not* reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time before needing to reach net zero by 2050 does *not* seem to be a sustainable solution. Instead, alternative methods of steel production such as scrap steel recycling emit about 80% less CO_2 per tonne of crude steel than other forms of steel production used today, and green hydrogen leading to the production of "green steel"[215] looks like a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production 'green'.

In all of these industrial applications, CCS/CCUS could be studied if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- the liability of the projects is not handed over to the taxpayers.

Lessons Learned: Insights for the Way Forward

The natural gas processing and power sector, where carbon capture technologies would extend the life of fossil fuel assets (even if its use could overcome historical technical and financial issues), is not in line with net zero goals.

There are a few sub-sectors for industrial application, however, where carbon capture could be considered an interim option for decarbonisation if it doesn't distract the research and development studies being done in parallel to reinvent the production process. Even in such sub-sectors, such as cement, the technical prosperity of the technology is uncertain. Considering the climate clock is ticking, rigorous environmental and technical conditions need to be satisfied if these few applications are to be greenlit.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications but with common processes as in these industries, as well as other solutions being developed and

[215] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.

researched in parallel, future CCS/CCUS applications in the steel and cement industry could be projected to some extent.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green cement. Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS should only be used if the technical performance reaches close to nominal capture capacities, contrasting with general trends of its application throughout history. Also, it could be considered an interim option as long as it does not divert financial flows from fundamental and innovative solutions reinventing the cement production process.

For other industrial applications, wherever hydrogen is applicable technically, green hydrogen seems to be the way to go due to the financial and imminent cost-efficiency.

Appendix 1

Project	Flagship Aspect	Year Capturing Started	Type	Country	Size[216] (Mtpa)	Sector	Performance Against Designed Capture Rate[217]	Comment
Abu Dhabi	The first and only CCS plant in the steel sub-sector	2016	Enhanced oil recovery (CCUS	UAE	0.8	Industrial (hard-to-abate sector)	No data has been published publicly	The project is 100% government owned
Boundary Dam	The only project operating in the power sector worldwide	2014	Mostly enhanced oil recovery (CCUS)	Canada	1	Power sector	Under-performing by about 50%	A 50-year-old coal power plant retrofitted with the carbon capture facility
Coffeyville	The largest project operating in the fertiliser production sub-sector	2013	Enhanced oil recovery (CCUS	U.S.	0.9	Industrial (chemical production)	No public data was found on the lifetime performance. Only some research shows that the plant over-performed during 2017–2019 by about 16%.	The CO_2 was vented until the year 2013, then some agreements with nearby oil companies were finalised to sell the CO_2
Gorgon	Largest and one of the more recent CCS projects in the world	2019	Dedicated geological structure (CCS)	Australia	4	Gas processing sector	Under-performing by about 50%	Started after 3.5 years delay with a track record of technical failures. Compensating under-performance will cost up to US$184 million.
Great Plains	The largest carbon capture project in all sectors other than natural gas processing	2000	Enhanced oil recovery (CCUS)	U.S.	3	Industrial (chemical production)	Lifetime under-performance of 20–30%	The project started capturing CO_2 16 years after the syngas plant was commissioned. In 2022, it has been planned to be redeveloped into a blue hydrogen project.
Illinois Industrial Carbon Capture and Storage (IL-CCS)	The largest and the latest project commissioned in the ethanol production sub-sector	2017	Dedicated geological structure (CCS)	U.S.	1	Industrial (chemical production)	Under-performing by about 45–50%	The project was 68% government funded. It has only captured about 12% of the yearly total CO_2 emissions of the biofuel plant so far
In Salah	One of the largest operating CCS projects of our time	2004	Dedicated geological structure (CCS)	Algeria	1.1	Gas processing sector	Failed after seven years of operation	Started in 2004. Concerns about possible vertical leakage into the caprock led to investigations, and finally, the project was suspended in 2011

[216] There are different sizes for some projects in different sources. In those cases, the average size has been considered.
[217] For some of the projects, scattered data from different sources has been complied to calculate the performance. An estimated interval is provided for the performance.

Kemper	It was planned to be a first-of-a-kind plant, capturing CO_2 from producing gasified coal, and using gas in the modified gas power plant to produce electricity	2014 (without Carbon Capture)	Enhanced oil recovery (CCUS)	U.S.	3	Power sector	Failed to be started	Technical problems led to a 250% increase in the previously estimated cost of the project from U$3b to US$7.5 billion. The carbon capture idea was cancelled in 2017. It was the most expensive power plant ever built.
Petra Nova	The only project in the power sector in the U.S.	2017	Enhanced oil recovery (CCUS)	U.S.	1.4	Power sector	Under-performed by 17% in four years of its operation and then shut down.	It was mothballed indefinitely in 2020 citing low oil prices during the COVID-19 pandemic
Quest	One of the operating projects in the hydrogen production sub-sector operating at its design capacity	2015	Dedicated geological structure (CCS)	Canada	1.1	Industrial (hydrogen production)	Performing close to the capture capacity	The project got off the ground thanks to huge government funding estimated at C$95 per tonne of CO_2 captured until the end of the project's lifetime. It captures 35% of the CO_2 emissions of the oil upgrader.
Shute Creek	Largest and one of the oldest carbon capture projects in the world	1986	Enhanced oil recovery (CCUS)	U.S.	7	Gas processing sector	Lifetime under-performance of 36%	It is estimated that the lifetime under-performance of the project against its capturing capacity is approximately equivalent to the combined emissions from Sweden and Denmark in 2019
Sleipner	First commercial carbon capture project with a dedicated geological structure worldwide	1996	Dedicated geological structure (CCS)	Norway	0.9	Gas processing sector	Performing close to the capture capacity	It is among a few successful cases located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers. The gas project is in its tail of production lifetime.
Snøhvit	One of the two successful Norwegian carbon capture projects	2007	Dedicated geological structure (CCS)	Norway	0.7	Gas processing sector	Performing close to the capture capacity	It is one of the successful cases which is located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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Cite this: *Energy Environ. Sci.*, 2019, **12**, 3567

The health and climate impacts of carbon capture and direct air capture

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Data from a coal with carbon capture and use (CCU) plant and a synthetic direct air carbon capture and use (SDACCU) plant are analyzed for the equipment's ability, alone, to reduce CO_2. In both plants, natural gas turbines power the equipment. A net of only 10.8% of the CCU plant's CO_2-equivalent (CO_2e) emissions and 10.5% of the CO_2 removed from the air by the SDACCU plant are captured over 20 years, and only 20–31%, are captured over 100 years. The low net capture rates are due to uncaptured combustion emissions from natural gas used to power the equipment, uncaptured upstream emissions, and, in the case of CCU, uncaptured coal combustion emissions. Moreover, the CCU and SDACCU plants both increase air pollution and total social costs relative to no capture. Using wind to power the equipment reduces CO_2e relative to using natural gas but still allows air pollution emissions to continue and increases the total social cost relative to no carbon capture. Conversely, using wind to displace coal without capturing carbon reduces CO_2e, air pollution, and total social cost substantially. In sum, CCU and SDACCU increase or hold constant air pollution health damage and reduce little carbon before even considering sequestration or use leakages of carbon back to the air. Spending on capture rather than wind replacing either fossil fuels or bioenergy always increases total social cost substantially. No improvement in CCU or SDACCU equipment can change this conclusion while fossil fuel emissions exist, since carbon capture always incurs an equipment cost never incurred by wind, and carbon capture never reduces, instead mostly increases, air pollution and fuel mining, which wind eliminates. Once fossil fuel emissions end, CCU (for industry) and SDACCU social costs need to be evaluated against the social costs of natural reforestation and reducing nonenergy halogen, nitrous oxide, methane, and biomass burning emissions.

Received 24th August 2019,
Accepted 21st October 2019

DOI: 10.1039/c9ee02709b

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Broader context

The Intergovernmental Panel on Climate Change concludes that carbon capture and storage/use (CCS/U) and synthetic direct air carbon capture and storage/use (SDACCS/U) are helpful technologies for avoiding 1.5 °C global warming. However, no study has evaluated their performance or social cost compared with merely replacing fossil with renewable electricity. Here, data from CCU and SDACCU equipment powered by natural gas are evaluated. Only 10.8% of the CCU plant's CO_2-equivalent (CO_2e) emissions and 10.5% of the CO_2 removed from the air by SDACCU are captured over 20 years; only 20–31% are captured over 100 years. Moreover, both plants increase air pollution and social cost *versus* no capture. Powering the equipment with wind instead of gas reduces CO_2e but allows the same pollution as and increases the social cost *versus* no capture. Replacing coal with wind (without capture) reduces CO_2e, pollution, and social cost substantially. In sum, spending on capture rather than wind replacing fossil or bioenergy always increases social cost. No improvement in CCU or SDACCU equipment can change this conclusion while fossil emissions exist. Once fossil emissions end, CCU (for industry) and SDACCU social costs must be evaluated against those of reforestation and reducing nonenergy halogen, nitrous oxide, methane, and biomass burning emissions.

Introduction

Carbon capture and storage (CCS) and use (CCU) involve the installation of equipment in a coal, natural gas, oil, or biomass electric power or heat generating facility to remove carbon dioxide (CO_2) from the exhaust and either sequester it underground or in a material (CCS) or sell it for industrial use (CCU).

Synthetic direct air carbon capture and storage (SDACCS) or use (SDACCU) is the removal of CO_2 from the air by chemical reaction. Upon removal, the CO_2 is either sequestered (SDACCS) or sold (SDACCU). SDACCS differs from natural direct air carbon capture and storage (NDACCS), which is the natural removal of carbon from the air by either planting trees or reducing biomass burning.

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Both CCS/U and SDACCS/U have been proposed as technologies to reduce atmospheric CO_2 and global warming. For example, IPCC[1] states that "capture, utilization, and storage" (CCS/U) can help reduce 75–90% of global CO_2 emissions and that it is "technically proven at various scales." They also identify SDACCS as a method to limit warming to 1.5 °C.

Historically, researchers have assumed CCS/U removes 85–90% of CO_2 exhaust with an energy penalty of ~25%.[2–4] An energy penalty is the additional electricity required to run the carbon capture equipment per unit electricity produced by the power plant for normal electricity consumption. However, until recently,[5] no public data from a commercial power plant with CCU were available to test these numbers. Similarly, until recently,[6] no data were available to evaluate an operating SDACCU plant. Models have also not evaluated the social cost of air pollution that CCS/U and SDACCS/U increase due to their energy use. Air pollution already kills 4–9 million people worldwide annually.[7] Evaluating the emissions and social (energy plus health, plus climate) cost of any proposed technology is critical given the enormous cost of eliminating world emissions (~$100 trillion – Table S9 of ref. 8).

Prior studies have also not evaluated the opportunity cost of using renewable electricity to power CCS/U or SDACCS/U equipment instead of using the renewable electricity to displace fossil fuel power plants. Given limited national budgets, the enormous cost of reducing global air pollution and carbon emissions, and limitations in land areas available in each country to install renewables to replace fossil energy, it is essential to compare the air pollution and carbon emissions of using renewables to power carbon capture equipment with, instead, displacing fossil fuel electricity directly with renewables, thus avoiding emissions in the first place.

Coal-CCU plant

This study first quantifies the carbon dioxide equivalent (CO_2e) emissions from a retrofitted pulverized coal boiler connected to a steam turbine at the W. A. Parish coal power plant near Thompsons, Texas. The plant was retrofitted with carbon capture (CC) equipment as part of the Petra Nova project and began using the equipment during January 2017. The CC equipment (240 MW) receives 36.7 percent of the emissions from the 654 MW boiler. The equipment requires about 0.497 kWh of electricity to run per kWh produced by the coal plant (Table 2, footnote g). A natural gas turbine with a heat recovery boiler was installed to provide this electricity. A cooling tower and water treatment facility were also added. The retrofit cost $1 billion ($4200 per kW) beyond the coal plant cost.[9]

CO_2 from the gas turbine is not captured. Natural gas production also has upstream CO_2e emissions, including CH_4 leaks, which are not captured. Upstream CO_2 and CH_4 emissions from the coal plant are also uncaptured. Table 1 shows the January through June CO_2 coal combustion emission data[5] from the plant before (in 2016) and after (in 2017) the addition of the CC equipment. The table also shows the gas combustion emissions from powering the CC equipment. The table then

Table 1 Columns a–d: raw emissions for January through June 2016 and 2017 from the 654 MW (-all-coal) Petra Nova coal-CCU unit.[5] The 2016 data are before carbon capture was added. The 2017 data include combustion CO_2 from the coal plant and, separately, from the natural gas combined cycle turbine installed to run the CC equipment. Columns e–h: emissions (in units of kg-CO_2 per MWh) for the 240 MW (coal-CC) portion of the 654 MW coal unit subject to carbon capture in 2016 and 2017. Column e equals column (a) multiplied by K = 0.4536 kg lb^{-1}. Column f equals $[b - a(1 - F)]K/F$, where b and a are the CO_2 stack emission rates for each month in 2017 (column b) and 2016 (column a), respectively, and F = 0.367 = 240 MW/654 MW is the fraction of the coal unit subject to carbon capture. Column g equals column c multiplied by K/F

	(a) 2016 coal CO_2 no CC lb-CO_2 per MWh-all-coal[5]	(b) 2017 coal CO_2 with CC lb-CO_2 per MWh-all-coal[5]	(c) 2017 gas CO_2 with CC lb-CO_2 per MWh-all-coal[5]	(d) 2017 total CO_2 with CC lb-CO_2 per MWh-all-coal = $b + c$	(e) 2016 coal CO_2 no CC kg-CO_2 per MWh-coal-CC = aK	(f) 2017 coal CO_2 with CC kg-CO_2 per MWh-coal-CC = $[b - a(1 - F)]K/F$	(g) 2017 gas CO_2 with CC kg-CO_2 per MWh-coal-CC = cK/F	(h) 2017 total CO_2 with CC kg-CO_2 per MWh-coal-CC = f + g
Jan	2060	1500	220	1720	934.4	242.2	271.9	514.1
Feb	2110	1615	225	1840	957.1	345.2	278.1	623.3
Mar	2130	1950	60	2010	966.2	743.7	74.2	817.8
Apr	2050	1550	155	1705	929.9	311.8	191.6	503.4
May	2010	1640	160	1800	911.7	454.4	197.8	652.2
Jun	1950	1550	155	1705	884.5	390.1	191.6	581.7
Average	**2052**	**1634**	**163**	**1797**	**930.6**	**414.6**	**200.9**	**615.4**

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translates the emissions from the full 654 MW coal unit to the 240 MW portion of the unit subject to CC. When upstream emissions are excluded, the CC equipment captures an average of only 55.4% (Table 2) of coal combustion CO_2 (rather than 90%) and only 33.9% of coal plus gas combustion CO_2.

Table 2 and Fig. 1 expand results from Table 1 to account for upstream emissions from the mining and processing of coal and natural gas. The CC equipment reduces coal and gas combustion plus upstream CO_2 a net of only 10.8% over 20 years (Fig. 1) and 20% over 100 years. 20 years is a relevant time frame to avoid 1.5° global warming and resulting climate feedbacks.[1]

When wind, instead of gas, is used to power the CC equipment, CO_2e decreases by 37.4% over 20 years and 44.2% over 100 years compared with no CC (Table 2 and Fig. 1). The CO_2e decrease exceeds that in the CCU-gas case because wind powering CC equipment case does not result in any combustion or upstream emissions from wind, as seen in Fig. 1.

However, using the wind electricity that powers the CC equipment instead to replace coal electricity directly at the same plant reduces CO_2e by 49.7% compared with no CC (Table 2 and Fig. 1). It is not 100% because only the wind used to run the capture equipment replaces coal. More wind would be needed to replace the whole coal plant. This third strategy is the best for reducing CO_2e among the three cases. Using solar PV to replace coal directly results in a similar benefit as using wind.

But, CO_2e is only part of the story. Because CCU equipment does not capture health-affecting air pollutants, air pollution emissions continue from coal and rise by about 25% compared with no capture from the use of natural gas to run the Petra Nova equipment (Table 2). Even when wind powers the CC equipment, air pollution from the coal plant continues as before (but not from using the new wind turbine). Only when wind partially replaces the use of coal itself does air pollution decrease by ~50% (Table 2).

The equipment cost of new coal and wind electricity in the U.S. are a mean of $102 per MWh and $42.5 per MWh, respectively.[10] The capital cost of CC equipment, $4200 per kW,[9] is about 74% the capital cost of a new coal plant ($5700 per kW),[10] suggesting that new coal plus CCU is 1.74 × $102 per MWh/$42.5 per MWh = 4.2 times the equipment cost of new wind. Since CC equipment reduces only 10.8% of coal CO_2e over 20 year and 20% over 100 year, the equipment for coal-CCU powered by natural gas alone costs 39 and 21 times that of wind-replacing coal per mass-CO_2 removed over 20 and 100 years, respectively.

Major additional social costs associated with coal electricity generation are air pollution and climate costs. The health cost of coal emissions in the U.S. is calculated as a mean of $80 per MWh, which is much lower than the world average ($169 per MWh, Table 2, footnote m). Since the use of CC equipment requires 50% more electricity than the coal plant produces but the health cost of natural gas emissions are about half those of coal, the use of gas to run the CC equipment increases health costs by ~25% compared with no capture (Table 2, row o). Mean climate costs of U.S. emissions are estimated as $152 per MWh, close to the world mean of $160 per MWh (Table 2, footnote m). CC equipment with natural gas is estimated to reduce this cost by only 10.8% and 20% over 20 and 100 years, respectively (Table 2, row n).

In sum, the total social cost (equipment plus health plus climate cost) of coal-CCU powered by natural gas is over twice that of wind replacing coal directly (Table 2 and Fig. 1). Moreover, the social cost of coal with CC powered by natural gas is 24% higher over 20 years and 19% higher over 100 years than coal without CC. Thus, no net social benefit exists of using CC equipment. In other words, from a social cost perspective, using CC equipment powered by natural gas causes more damage than does doing nothing at all.

When wind powers CC equipment, the social costs are still 6% and 2% higher over 20 and 100 years, respectively, than not using CC (Table 2 and Fig. 1). Although wind-powering-CC decreases CO_2e, thus climate cost, compared with coal without CC, wind-CC allows the same air pollution emissions from coal as no CC, and the cost of the wind plus CC equipment outweighs the CO_2e cost reduction (Fig. 1).

Only when wind replaces coal electricity production directly does the total social cost drop 43% compared with no CC (Table 2). This is the best scenario. A similar benefit occurs if wind replaces natural gas and no CC is used.

Some may argue that (a) the six months of data with *versus* without the CC equipment are insufficient for drawing conclusions about this plant and (b) future plants may improve upon the Petra Nova plant. Whereas both points are valid, in order for the social cost of using the CC equipment powered by natural gas to be less than that of doing nothing, the CO_2e reemitted by the Petra Nova plant would need to be 37% or less instead of 89.8% over 20 years. However, this is all but impossible, because 59.2% of the re-emissions is due to upstream coal and gas emissions and natural gas combustion emissions, so little to do with how effective the CC equipment is at capturing carbon. In other words, even if the CC equipment captured 100% of the stack CO_2, which no-one is proposing is feasible, the reemissions would still be 59.2%. This is because controlling 100% of the coal stack emissions can reduce only 40.8% of the total upstream plus stack coal emissions due to the additional upstream and combustion emissions of the gas plant over a 20 year time frame. As such, the data indicate that no technological improvement will result in the social cost of using CC equipment powered by natural gas being less than that of not using the equipment.

When CC is powered by wind, it is theoretically possible, albeit challenging, to reduce the total social cost below that of no CC. However, it is impossible to reduce the total social cost below that of wind replacing coal electricity directly because wind-powering-CC also incurs a CC equipment cost and never reduces air pollution or mining from coal, whereas wind replacing coal incurs no CC equipment cost and eliminates coal air pollution and mining.

SDACCU plant

This section evaluates the efficiency of CO_2 removal from the air by an SDACCU facility,[6] where electricity for the air capture

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Table 2 Comparison of relative CO_2e emissions, electricity use, and electricity social costs among three scenarios related to the Petra Nova coal-CCU facility, each over a 20 year and 100 year time frame. The first scenario is using natural gas to power the carbon capture (CC) equipment. This is based on data from the Petra Nova facility (Table 1). The second scenario is running the CC equipment with onshore wind instead of natural gas. The third is using the same quantity of wind electricity required to run the CC equipment to instead replace coal electricity from the coal plant. In all cases, the additional energy required to run the CC equipment is equivalent to 49.7% of the energy output of the coal plant (footnote g). The coal plant has a nameplate capacity of 654 MW, but only 240 MW (36.7%) is subject to CC. The numbers in the table are all based on the portion subject to CC. All emission units (including of natural gas emissions) are g-CO_2e per kWh-coal-electricity-generation

	Coal with gas-powered CC 20 year	Coal with gas-powered CC 100 year	Coal with wind-powered CC 20 year	Coal with wind-powered CC 100 year	Wind used for CC replacing coal + remaining coal 20 year	Wind used for CC replacing coal + remaining coal 100 year
(a) Upstream CO_2 from coal[a]	97.2	97.2	97.2	97.2	48.9	48.9
(b) Upstream CO_2e of leaked CH_4 from coal[b]	353	140	353	140	177.6	70.4
(c) Coal stack CO_2 before capture[c]	930.6	930.6	930.6	930.6	468.1	468.1
(d) Total coal CO_2e before capture (a + b + c)	1381	1168	1381	1168	695	587
(e) Remaining stack CO_2 after capture[d]	414.6	414.6	414.6	414.6	—	—
(f) CO_2 captured from stack (*c*–*e*)	516.0	516	516	516	—	—
(g) Percent stack CO_2 captured (f/c)	55.4	55.4	55.4	55.4	—	—
(h) CO_2 emissions gas combustion[e]	200.9	200.9	0	0	0	0
(i) Upstream CO_2e of CH_4 from gas leaks[f]	139.2	55.03	0	0	0	0
(j) Upstream CO_2 from gas mining, transport[g]	26.85	26.85	0	0	0	0
(k) Total CO_2e emissions (a + b + e + h + i + j)	1,232	934.5	865	652	695	587
(l) Percent of coal CO_2e re-emitted (k/d)[h]	**89.2**	**80.0**	**62.6**	**55.8**	**50.3**	**50.3**
(m) Percent of coal CO_2e captured (100-l)	**10.8**	**20**	**37.4**	**44.2**	**49.7**	**49.7**
(n) Relative CO_2e to original (l/100)[i]	0.892	0.80	0.626	0.558	0.503	0.503
(o) Relative air pollution to original[j]	1.25	1.25	1.0	1.0	0.503	0.503
(p) Energy required relative to original[k]	1.497	1.497	1.497	1.497	1	1
(q) Private energy cost per kWh relative to original[l]	1.74	1.74	1.74	1.74	0.71	0.71
(r) Social cost before changes ($ per MWh)[m]	334	334	334	334	334	334
(s) Social cost after changes ($ per MWh)[n]	413	399	353	342	189	189
(t) Social cost ratio (s/r)	1.24	1.19	1.06	1.02	0.57	0.57

[a] Coal upstream emissions are estimated as 27 g-CO_2 per MJ = 97.2 g-CO_2 per kWh.[11] Upstream emissions include emissions from fuel extraction, fuel processing, and fuel transport. Upstream CO_2 emissions (from the portion of the coal plant not replaced) for the wind-replacing some coal cases (last two columns) are the same as in the other cases, but multiplied by 0.503, which equals 1 minus the fraction of coal electricity used to run the carbon capture equipment, which is derived in footnote g. Since the electricity used to run the CC equipment is used to replace coal in this case, upstream coal emissions are reduced accordingly. [b] For coal, the 100 year CO_2e from CH_4 leaks is estimated from (ref. 12, slide 17). The emission factor is derived from that number and the 100 year GWP of CH_4, 34 from ref. 13. The 20 year CO_2e is then derived from the resulting emission factor (4.1 g-CH_4 per kWh) and the 20 year GWP of CH_4, 86. Emissions in the wind cases are reduced as described under footnote a. [c] The average coal stack emission rate for the Petra Nova facility in 2016, prior to the addition of CC equipment, is from Table 1, column e. In the wind-replacing-coal cases (last two columns), the emission rate is reduced as described under footnote a. [d] The coal-stack CO_2 remaining after capture is from Table 1, column f. [e] The natural gas combustion emissions resulting from powering the CC equipment is from Table 1, column g. [f] Natural gas upstream leaks are obtained by dividing the raw emission rate of CO_2 from natural gas for each month January through June 2017 from Table 1 (in kg-CO_2 per MWh-coal-electricity) by the molecular weight of CO_2 (44.0098 g-CO_2 per mol) to give the moles of natural gas burned per MWh-coal-electricity. Multiplying the moles burned per MWh by the fractional number of moles burned that are methane (0.939)[14] and the molecular weight of methane (16.04276 g-CH_4 per mol) gives the mass intensity of methane in the natural gas burned each month (kg-CH_4-burned per MWh-coal-electricity). The upstream leakage rate of methane is then the kg-CH_4-burned per MWh-coal-electricity multiplied by $L/(1-L)$, where $L = 0.023$ is the fraction of all methane produced (from conventional and shale rock sources) that leaks,[15] giving the methane leakage rate in kg-CH_4 per MWh-coal-electricity. This leakage rate is conservative based on a more recent full-lifecycle leakage rate estimate of methane from shale rock alone of $L = 0.035$.[16] Using the latter estimate would result in CCS/U with natural gas re-emitting even more CO_2e than calculated here. Multiplying the kg-CH_4 per MWh-coal-electricity by the 20- and 100 year GWPs of CH_4 (86 and 34, respectively)[13] gives the CO_2e emission rate of methane leaks each month. The monthly values are linearly averaged over January through June 2017. [g] The non-CH_4 upstream CO_2e emissions rate is estimated as 15 g-CO_2 per MJ-gas-electricity = 54 g-CO_2 per kWh-gas-electricity.[11] Multiplying that by 0.497 MWh-electricity from natural gas per MWh-coal-electricity produced gives 26.8 kg-CH_4 per MWh-coal-electricity. 0.497 MWh-electricity from natural gas per MWh-coal-electricity produced, or 49.7%, is calculated by dividing the average gas combustion emission from Petra Nova (200.9 g-CO_2 per kWh-coal from the present table) by the combustion emissions per unit electricity from a combined cycle gas plant (404 g-CO_2 per kWh-natural-gas). [h] The percent CO_2 reemitted for the wind cases (last two columns) equals row k for the wind cases divided by row d for either of the non-wind cases. [i] CO_2e emissions relative to coal with no CC equipment. [j] Air pollution emissions relative to coal with no CC equipment. In the natural gas cases, all air pollution from coal emissions still occurs. Although gas is required to produce 0.497 MWh of electricity for the CC equipment per MWh of coal electricity, gas is assumed to be 50% cleaner than coal, so the overall air pollution in this case increases only 25% relative to the no CC case. In the wind-CC cases, all upstream and combustion emissions from coal still occur. [k] The electricity required (for end-use consumption plus to run the CC equipment) in all CC cases is 49.7% higher than with no CC. In the wind-replacing coal case, no electricity is needed to run the CC equipment, but electricity is still needed for end use. [l] The private energy cost in all CC cases is assumed to be 74% higher than coal with no CC because the CC equipment (including the gas plant) costs $4200 per kW, which represents about 74% of the mean capital cost of a new coal plant ($5700 per kW) from.[10] For simplicity, it was assumed that the cost of a wind turbine running the CC equipment was the same as of a gas turbine running the equipment. In the wind-replacing-coal cases, the cost of coal was assumed to be a mean of c = $102 per MWh and of wind, w = $42.5 per MWh.[10] The final ratio was calculated as $(0.503c + 0.497w)/c$. [m] The social cost before changes is the private energy cost of new coal without CCU [$102 per MWh from ref. 10] plus air pollution mortality, morbidity, and non-health environmental costs of coal power plant emissions in the U.S. plus the global climate costs of U.S. emissions ($152 per MWh).[18] U.S. coal power plant emissions health costs are estimated as $80 per MWh, which is twice the background grid health cost of $40 per MWh.[17] In the worldwide average, from the same source, the health cost of background grid emissions is estimated as $169 per MWh, so use of the U.S. number here is likely to underestimate the health costs of using carbon capture outside the U.S. [n] The social cost after changes is the sum of the private energy cost multiplied by row q, the air pollution health cost multiplied by row o, and the climate cost multiplied by row n.

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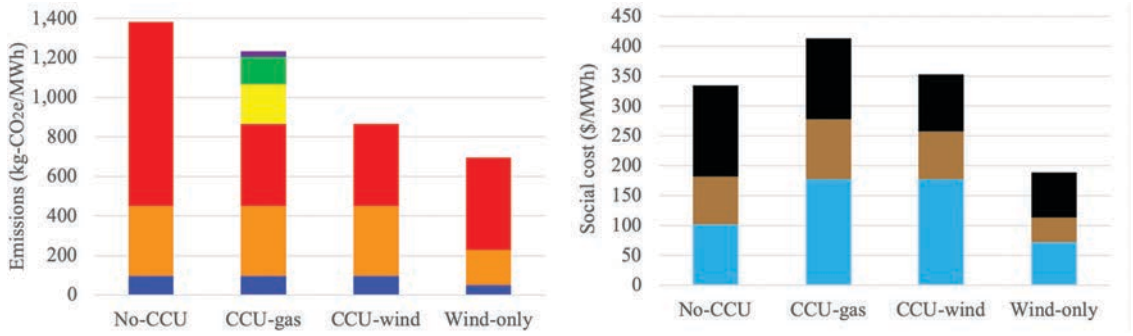


Fig. 1 Left: CO_2e emissions, averaged over 20 years, from the Petra-Nova coal plant before (No-CCU) and after (CCU-gas) the addition of CCU equipment powered by natural gas. Also shown are emissions when the CCU equipment is powered by wind energy (CCU-wind) and when the portion of wind energy used to power the CCU equipment is instead used only to replace a portion of the coal power (thus some power is generated by coal and some by wind). Blue is upstream CO_2e from coal mining and transport aside from CH_4 leaks; orange is upstream CO_2e from coal mining CH_4 leaks; red is coal combustion CO_2; yellow is natural gas combustion CO_2; green is CO_2e from natural gas mining and transport CH_4 leaks; and purple is natural gas mining and transport CO_2e aside from CH_4 leaks. Right: Mean estimate of social costs per unit electricity over 20 years generated by the coal plant (in the first three cases) or the residual coal plant plus replacement wind plant (fourth case) for each of the four cases shown on the left. Light blue is the cost of electricity generation plus CCU equipment; brown is air pollution health cost; and black is 20 year climate cost. All data are from Table 2.

(AC) equipment is provided by a natural gas combined cycle turbine.

Table 3 indicates that, averaged over 20 and 100 years, 89.5% and 69%, respectively, of all CO_2 captured by the AC equipment is returned to the air as CO_2e. The emissions come from mining, transporting, processing, and burning the natural gas used to power the equipment.

In comparison with taking no action, using SDACCU equipment powered by natural gas also increases air pollution due to the combustion and upstream emissions associated with natural gas. With no action, SDACCU further incurs an equipment cost. Thus, although SDACCU powered by natural gas reduces some CO_2e, the equipment cost and air pollution cost far outweigh that decrease, resulting in a near doubling of the total social cost per MWh of electricity use relative to the health and climate cost per MWh of coal power plant emissions (Fig. 2).

Even when zero re-emissions occur, such as when wind powers the SDACCU equipment, the mean social cost of using SDACCU still exceeds that of doing nothing (Fig. 2). On the other hand, using wind to replace coal electricity instead of to run the AC equipment eliminates CO_2e and air pollution emissions and their associated costs from the coal. The resulting social cost is ~15% of that from wind powering SDACCU equipment (Table 3 and Fig. 2). A similar result is found when wind replaces a natural gas plant instead of a coal plant. In fact, there is no case where wind powering an SDACCU plant has a social cost below that of wind replacing any fossil fuel or bioenergy power plant directly. The reasons are that wind-powering-SDACCU always incurs an SDACCU equipment cost that wind alone never incurs and SDACCU always allows air pollution and mining to continue whereas wind always eliminates air pollution and mining.

Discussion

Tables 1–3 suggest virtually no carbon benefit of and greater air pollution damage from CCS/U and SDACCS/U before considering the disposition of the captured CO_2.

Three reasons this result has not been identified previously, aside from the lack of data, are that previous studies and models did not consider upstream fossil emissions, the air pollution social cost resulting from the additional energy needs, or the higher fossil emissions due to using renewable electricity for CC or AC equipment instead of to displace fossil electricity. Air pollutants not captured by CC or AC equipment from fossil or bioenergy plants include CO, NO_x, SO_2, organic gases, mercury, toxins, black and brown carbon, fly ash, and other aerosol components.

Ref. 4 found that even after assuming 90% capture by equipment (and ignoring upstream and combustion emissions to run the capture equipment), renewables return better on investment than CC. The results here suggest that a specific coal-CCU plant reduces only 10.5% and 20% of the plant's overall CO_2e over 20 and 100 years, respectively, while increasing air pollution and land degradation (from additional mining). More than half the re-emissions are due to upstream coal and gas emissions and natural gas combustion emissions to run the CC equipment. In addition, CC always incurs an equipment cost and never reduces air pollution, whereas renewables have no such equipment costs and always reduce air pollution. For all these reasons, renewables replacing fossil fuels or bioenergy are a lower social-cost investment to address climate than even[4] found.

SDACCS/U powered by natural gas similarly increases air pollution by increasing fossil energy consumption and upstream mining. Clean electricity used to run SDACCS/U equipment does not increase air pollution but keeps it the same. However, the social cost of using that clean electricity to replace fossil fuels or bioenergy is always lower than the social cost of using the electricity to run SDACCS/U equipment. The reasons are that SDACCU equipment always incurs a cost that renewables never incur and SDACCU always allows air pollution and fuel mining to continue, whereas renewables eliminate air pollution and fuel mining.

The results here are independent of the fate of the CO_2 after it leaves the CC equipment, thus apply to CC with bioenergy (*e.g.*, BECCS/U) or cement manufacturing. The CC equipment

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Table 3 Comparison of relative CO_2e emissions, electricity private costs, and electricity social costs among three scenarios related to the carbon engineering SDACCU plant, each over a 20 year and 100 year time frame. The first scenario is using an on-site natural gas (NG) combined cycle turbine to power the direct air capture (DAC) equipment. The DAC equipment does not capture the gas emissions; if it did, the results would be the same, since if the equipment captured turbine CO_2 emissions, it would not capture the equivalent CO_2 from the air. The third scenario involves using the same wind turbine electricity to instead replace coal power generation without using AC equipment. All emission units (rows a–f, i) are kg-CO_2e per MWh

	DAC with NG elec. 20 year	DAC with NG elec. 100 year	DAC with wind elec 20 year	DAC with wind elec. 100 year	Wind replacing coal 20 year	Wind replacing coal 100 year
(a) SDACCU removal from air[a]	825	825	825	825	—	—
(b) CO_2 emissions combined cycle gas turbine[b]	404	404	—	—	—	—
(c) Upstream CO_2e of CH_4 from gas leaks[c]	280	111	—	—	—	—
(d) Upstream CO_2 from gas mining, transport[d]	54	54	—	—	—	—
(e) Emission reduction due to replacing coal with wind[e]	0	0	0	0	−1381	−1168
(f) All emissions (b + c + d + e)	738	569	0	0	−1381	−1168
(g) Percent CO_2 returned (f/a)	**89.5**	**68.9**	**0**	**0**	—	—
(h) Percent CO_2 captured (100-g)	**10.5**	**31.1**	**100**	**100**	—	—
(i) Absolute emission reduction (a–f)	87	256	825	825	1381	1168
(j) Low SDACCU ($ per tonne-CO_2-removed)[a]	94	94	94	94	—	—
(k) High SDACCU ($ per tonne-CO_2-removed)[a]	232	232	232	232	—	—
(l) Low private electricity cost (aj/1000) ($ per MWh)[f]	78	78	78	78	29	29
(m) High private electricity cost (ak/1000) ($ per MWh)[f]	191	191	191	191	56	56
(n) Health cost of background grid ($ per MWh)[g]	40	40	40	40	40	40
(o) Ratio health cost of scenario to of background grid[h]	3	3	2	2	0	0
(p) Health cost of scenario (no) ($ per MWh)	120	120	80	80	0	0
(q) Climate cost of background grid ($ per MWh)[i]	152	152	152	152	152	152
(r) Ratio climate cost of scenario to of background grid[j]	0.937	0.781	0.403	0.294	0	0
(s) Climate cost of scenario (qr) ($ per MWh)	142	119	61.2	44.6	0	0
(t) Low social cost ($ per MWh) (l + p + s)	340	316	219	202	29	29
(u) High social cost ($ per MWh) (m + p + s)	454	430	333	316	56	56
(v) Low social cost ratio (row t-SDACCU/u-wind)	6.1	5.6	3.9	3.6	—	—
(w) High social cost ratio (row u-SDACCU/t-wind)	15.6	14.8	11.5	10.9	—	—

[a] Ref. 6. Assumes values for DAC with wind electricity are the same as DAC with natural gas electricity. [b] Ref. 19. [c] Same methodology as in Table 2, footnote f, but using the CO_2 combustion emissions from row (b) here. [d] Ref. 11. [e] Assumes wind that would otherwise be used to run the SDACCU equipment instead directly replaces coal electricity, its upstream CO_2 combustion, its upstream CH_4 leaks, and its stack combustion CO_2 emissions. The overall emission rates from coal are obtained from Table 2, row d. [f] Low and high wind electricity costs for wind-replacing coal are from.[10] Others are from the formula provided. [g] The U.S. health cost of $40 per MWh for the background grid per MWh is from ref. 17. [h] The ratio of the health cost in the scenario to that of the background grid is defined as zero for the wind-replacing coal case, since wind produces zero emissions during its operation. In comparison, wind running SDACCU equipment allows those coal emissions, which are about twice background grid emissions per unit energy, to continue, so the factor in that scenario is 2. Natural gas running SDACCU equipment not only allows those coal emissions to continue, but it also produces 50% more emissions, assumed equal to background grid emissions per MWh, so the factor in that scenario is 3. [i] The U.S. climate cost of $152 per MWh for the background grid is from ref. 17 and 18. [j] The ratio of the climate cost of the scenario to that of the background grid is defined as zero for the wind-replacing coal case, since wind produces zero emissions during its operation. For the other cases, it is simply the absolute CO_2e emission reduction in the case minus that in the wind case all divided by that in the wind case, where all values are from row i.

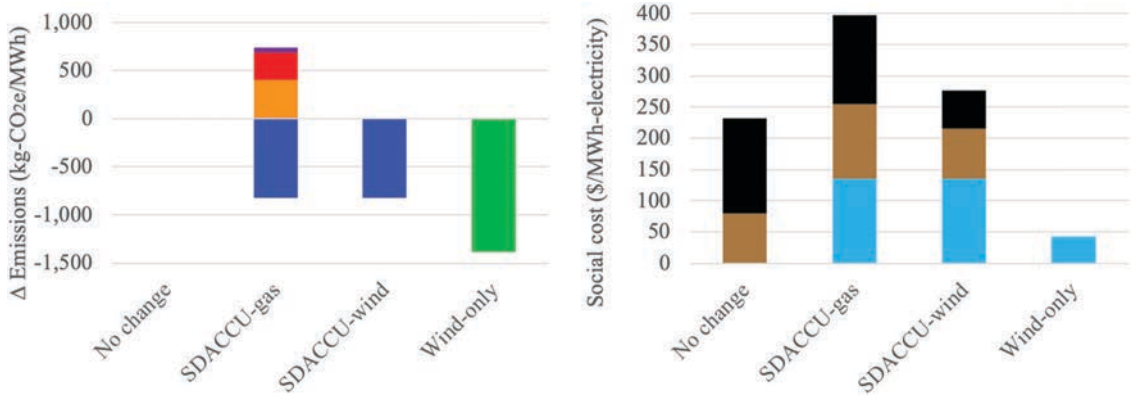


Fig. 2 Left: Change in CO_2e emissions, averaged over 20 years, per unit electricity needed to run SCACCU equipment resulting from either no action (no-change), using an SDACCU plant with equipment powered by natural gas (SDACCU-gas), using an SDACCU plant with equipment powered by wind (SDACCU-wind), and using the same quantity of wind required to run the SDACCU equipment but to replace coal power directly (wind-only). Blue is the removal of CO_2 from the air by the SDACCU equipment; orange is the natural gas turbine emissions; red is the CO_2e from natural gas mining and transport CH_4 leaks; purple is natural gas mining and transport CO_2e aside from CH_4 leaks; and green is the CO_2e emission reduction due to replacing coal power with wind power. Right: Mean estimate of social costs per unit electricity over 20 years for each of the four cases shown on the left. Light blue is the cost of equipment (either air capture equipment plus gas turbine, air capture equipment plus wind turbine, or wind turbine alone); brown is air pollution health cost; and black is 20-year climate cost. All data are from Table 3, except that the costs in the no-change case are the health and climate costs of coal power plant emissions ($80 per MWh health cost and $152 per MWh climate cost – Table 2, footnote m). Such emissions costs are used as the background because the wind-only case removes such emissions.

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always requires energy. If the energy comes from a fossil fuel, mining and combustion emissions from the fuel cancel most CO_2 captured. If it comes from a renewable, total social costs are still always greater than using the renewable to replace fossil fuels or bioenergy directly.

When the fate of captured CO_2 is considered, the problem may deepen. If CO_2 is sealed underground without leaks, little added emissions occur. If the captured CO_2 is used to enhance oil recovery, its current major application, more oil is extracted and burned, increasing combustion CO_2, some leaked CO_2, and air pollution. If the captured CO_2 is used to create carbon-based fuel to replace gasoline and diesel, energy is still required to produce the fuel, the fuel is still burned in vehicles (creating pollution), and little CO_2 is captured to produce the fuel with. A third proposal is to use the CO_2 to produce carbonated drinks. However, along with the issues previously listed, most CO_2 in carbonated drinks is released to the air during consumption. In addition, the quantity of CO_2 needed for carbonated drinks is small compared with the CO_2 released by fossil fuels globally.

Another argument for using SDACCS/U is that it will be needed for removing CO_2 from the air once all fossil fuels are replaced with renewables. If renewables are then used to power SDACCS/U they can reduce CO_2 without incurring an air pollution cost. However, the question at that point is whether growing more trees, reducing biomass burning, or reducing halogen, nitrous oxide, and non-energy methane emissions is a more cost-effective method of limiting global warming.

In sum, SDACCS/U and CCS/U are opportunity costs, not close to zero-carbon technologies. For the same energy cost, wind turbines and solar panels reduce much more CO_2 while also reducing fossil air pollution and mining, pipelines, refineries, gas stations, tanker trucks, oil tankers, coal trains, oil spills, oil fires, gas leaks, gas explosions, and international conflicts over energy. CCS/U and SDACCS increase these by increasing energy use and always increase total social costs relative to using renewables to eliminate fossil fuel and bioenergy power generation directly.

Author contributions

M. Z. J. performed the research and wrote the paper.

Data and materials availability

Virtually all data are provided within the paper and references therein but any data not provided may be obtained from the author.

Conflicts of interest

Author declares no competing interests.

Acknowledgements

This paper was not funded by any entity.

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Lake Nyos disaster, Cameroon, 1986: the medical effects of large scale emission of carbon dioxide?

Peter J Baxter, M Kapila, D Mfonfu

Abstract

Carbon dioxide was blamed for the deaths of around 1700 people in Cameroon, west Africa, in 1986 when a massive release of gas occurred from Lake Nyos, a volcanic crater lake. The clinical findings in 845 survivors seen at or admitted to hospital were compatible with exposure to an asphyxiant gas. Rescuers noted cutaneous erythema and bullae on an unknown proportion of corpses and 161 (19%) survivors treated in hospital; though these lesions were initially believed to be burns from acidic gases, further investigation suggested that they were associated with coma states caused by exposure to carbon dioxide in air.

The disaster at Lake Nyos and a similar event at Lake Monoun, Cameroon, two years previously provide new information on the possible medical effects of large scale emissions of carbon dioxide, though the presence of other toxic factors in these gas releases cannot be excluded.

Introduction

On 21 August 1986 about 1700 people were killed by a massive release of gas from Lake Nyos, a volcanic crater lake situated in a remote, mountainous part of north west Cameroon, west Africa. Though the gas is believed to have been volcanic, its precise composition and mechanism of release remain uncertain. Volcanic gases typically contain water vapour, carbon dioxide, sulphur dioxide, hydrogen sulphide, hydrogen chloride, hydrogen fluoride, and carbon monoxide.[1] Carbon dioxide, however, was the only gas detected in samples of lake water,[2,3] suggesting that this was the predominant if not only gas released. In a strikingly similar event in August 1984 at Lake Monoun, about 100 km south of Lake Nyos, 37 people were killed by a cloud of gas also believed to have been carbon dioxide.[4] To our knowledge catastrophic large scale emissions of carbon dioxide from natural or industrial sources have not been reported before, though an eruption of gas from the Sinila volcano, Dieng Plateau, Indonesia, caused 139 deaths in 1979.[5] Clinical information from these previous events is scarce, and the disaster at Lake Nyos provided an opportunity to study the effects of such gas releases in more detail. We summarise the main clinical findings to draw attention to this newly recognised hazard in volcanic areas and to the possible effects on populations of large scale emissions of carbon dioxide.

Background and findings

Lake Nyos is about 1·9 km long, 1·2 km wide, and 200 m deep; less than 3 km to the north the valley floor is more than 250 m below the surface level of the lake.[2,3] The release occurred between 9 and 10 pm on a calm night, and the gas flowed northwards, causing heavy loss of life in the settlements of Nyos, Cha, and Subum, and along valleys in a sparsely populated farming area some 20 km long by 15 km wide[6] (fig 1). Most of the native population were either subsistence farmers or Fulani cattle raisers; many cattle as well as other animals were killed. Survivors near the lake recalled hearing wind or animals being disturbed and some reported a smell of gunpowder or rotten eggs before suddenly losing consciousness. News of the event was slow to emerge, and when a rescue team entered the area 36 hours later it came upon an awesome scene. One of us (DM) was a member of the team.

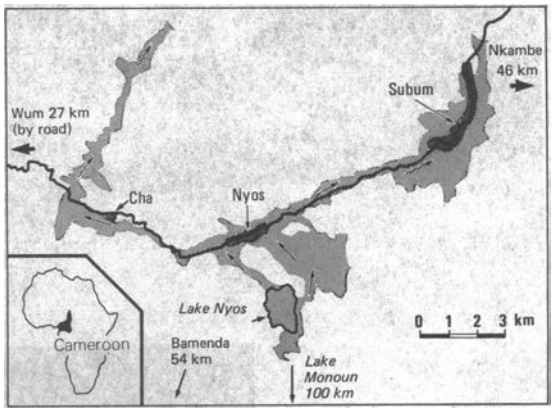


FIG 1—*Direction of flow of gas (arrows; stippled area) from Lake Nyos into adjacent valleys*

SURVIVORS

From at most about 5000 survivors living in the affected area, 548 were admitted to the two hospitals in Wum and Nkambe; a further 297 attended the hospitals over subsequent weeks. The cardinal presenting symptoms and signs in these two groups were collated from hospital records (table I) and showed a similar pattern,[6] except that virtually all the patients who were admitted, including those with skin lesions, were believed to have lost consciousness. Consciousness was seemingly lost for hours, and certainly overnight for many victims, though cultural and

TABLE I—*Main clinical findings in 845 survivors of gas eruption from Lake Nyos attending (n=297) or admitted (n=548) to hospital for treatment*

	No (%) of victims		No (%) of victims
Cough	262 (31)	Limb swelling	85 (10)
Haemoptysis	25 (3)	Vomiting	42 (5)
Dyspnoea	42 (5)	Diarrhoea	42 (5)
Eye irritation	42 (5)	Headache	220 (26)
Skin lesions resembling burns	161 (19)	Weakness/malaise	93 (11)
Limb weakness	51 (6)	Fever	101 (12)

Total No of records=845; total No of attendees=870; information missing in 25 cases.

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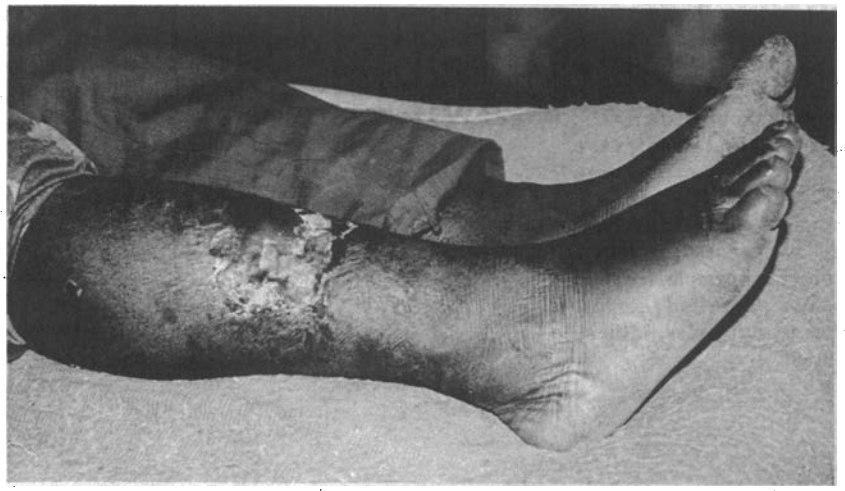
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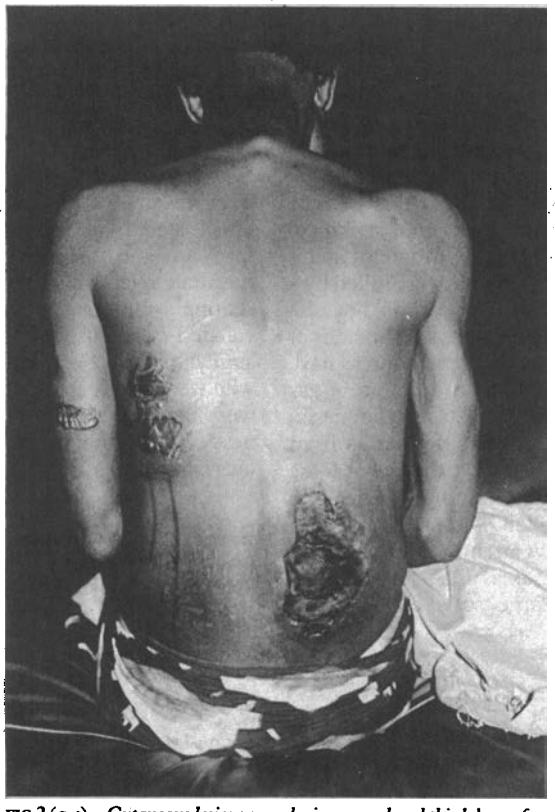
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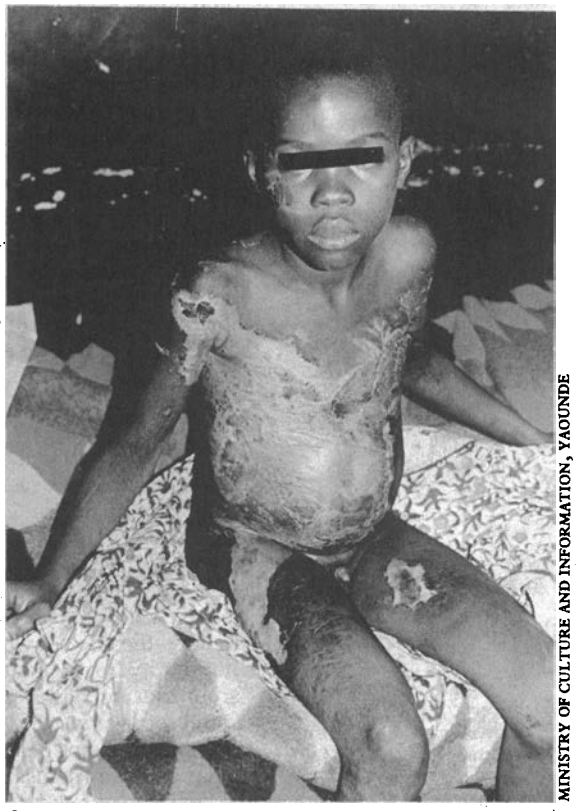
d



b



c



e

MINISTRY OF CULTURE AND INFORMATION, YAOUNDE

FIG 2 (*a-e*)—*Cutaneous lesions seen during second and third days after release of gas from Lake Nyos. (Photographs by DM)*

language difficulties made detailed history taking mostly impossible. Cough was a frequent complaint (262 cases; 31%), but difficulty with breathing was recorded in only 42 cases (5%); haemoptysis was also uncommon. Respiratory problems were treated with antibiotics, but three patients died of pneumonia. Only 42 patients had conjunctivitis or severe eye symptoms.

The commonest physical abnormalities seen on examination were erythema and other skin changes resembling burns (161 cases; 19%). In 36 of the hospital inpatients blistering or ulceration of the skin without underlying muscle necrosis was present which was initially believed to be due to the effects of acidic volcanic gases. These lesions were most often present on the face (table II) and mainly over the zygomatic region (fig 2*a*) but in other cases on the leg (fig 2*b*) or abdomen or back (fig 2*c-e*). Only five patients attributed their lesions to burns. Among those admitted to and attending the hospitals 51 patients (6%) had weakness of arms or legs, including footdrop and

TABLE II—*Distribution of sites of superficial and deep skin lesions in 548 survivors admitted to hospital*

	No of lesions		No of lesions
Face:		Abdomen	8
Zygoma	84	Back	1
Other	36	Arm	7
Neck	2	Leg	18
Chest	2	Over body	3

wristdrop, together with associated oedema (85 cases; 10%). Less specific complaints such as generalised body pains and headache were frequent, and 101 patients (12%) had fever (malaria was endemic in the area). Diarrhoea and dehydration were uncommon. In the hospital at Nkambe many patients were found to have transient proteinuria. There were seven miscarriages at under 20 weeks' gestation and four stillbirths, one at 32 weeks and three near term. Loss of smell or taste was not reported, but several patients complained of unilateral hearing loss after the event. The pattern of illness was the same regardless of where the survivors had been at the time of the release.

Most of the skin lesions were superficial and healed within two weeks. Patients with limb weakness also were improved within two weeks. There was no evidence of gross damage to the central nervous system or persistent respiratory disability in the inpatients; most of the survivors went to live in refugee camps and a year later were not reported to be suffering from mental or respiratory problems referable to the disaster.

CORPSES

The appearance and disposition of the corpses were not systematically recorded and necropsies were not performed before burial by the fourth day after the gas release; however, many (proportion unknown) had prominent skin bullae (figs 3 and 4). The gross appearances of the dead cattle, including the skin, showed nothing abnormal.

Foreign scientists and health workers invited by the Cameroon government did not arrive until at least one week after the release. A United States medical team performed a necropsy on a 30 year old man from Nyos who had died two days after admission to hospital at Wum (the body had been embalmed). The cause of death was pneumonia. The team exhumed a male victim at Subum, and the decomposing corpse showed evidence of pulmonary congestion and oedema. The carcase of a bull was also examined at Subum but the findings were non-specific. Additional material collected by Cameroonian doctors from a 30 year old man who died on 27 August showed congestion of the lungs and no other gross changes. These findings were in keeping with death from exposure to an asphyxiant gas.[3] The Japanese team performed a necropsy on a man who had died 90 minutes previously in Cha village on 30 August. The team found massive pulmonary congestion and an increased sulphate concentration in skin samples, suggesting that sulphur dioxide had been inhaled; this result, however, may have been due to the use of contaminated formaldehyde solution for preserving the samples or because the control skin collected in Japan was inappropriate (Japanese International Disaster Relief Team, unpublished observations).

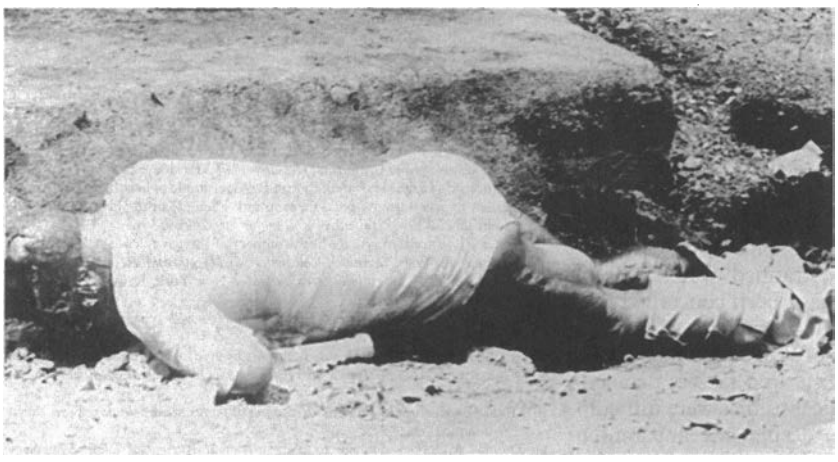


FIG 3—*Dead man found in Nyos village*

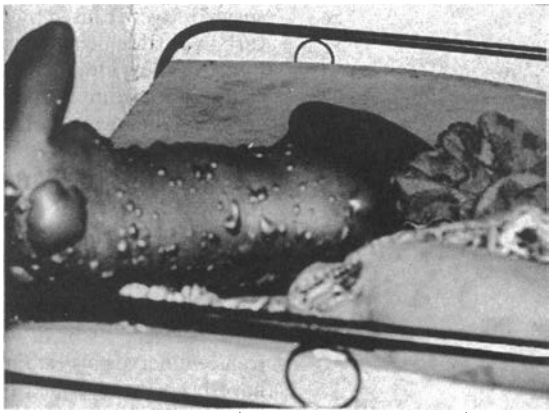


FIG 4—*Dead woman found inside house. (Photograph by DM)*

Discussion

The history of sudden loss of consciousness with coma lasting for hours followed by rapid recovery was more compatible with exposure to a high concentration of an asphyxiant than an irritant gas (or gases).[7] Irritant gases such as sulphur dioxide or hydrogen chloride would be more likely to have caused pulmonary oedema and severe irritation of the eyes and mucous membranes than was found, and these effects and their clinical sequelae would have persisted for longer than the 36 hours that it took before survivors reached hospital. The most likely explanation for the respiratory problems in a minority of patients was pulmonary oedema and consolidation due to prolonged coma, especially as most resolved rapidly after antibiotics.

The main asphyxiant volcanic gases are carbon dioxide, carbon monoxide, and hydrogen sulphide, but high concentrations of hydrogen sulphide can be excluded, as this agent is also very irritant.[8,9] Nevertheless, some survivors did report smelling gunpowder or rotten eggs, so that small amounts of sulphur dioxide and hydrogen sulphide cannot be dismissed. Further confirmation that acidic gases were not present in appreciable amounts was the absence of damage to foliage near the lake or where people died; concentrations of sulphur dioxide, hydrogen chloride, or hydrogen fluoride high enough to be lethal to man would have severely damaged plants.[10,11] Carbon dioxide was most likely to have been the main if not only gas released, as indicated by its abundance in the lake water together with normal amounts of sulphur and halides found in samples taken at depth after the event.[2] In addition, carbon dioxide is 1·5 times denser than air at normal temperature and would have readily flowed down into the valleys. Coma lasting for hours and the skin lesions recorded, however, have not been reported in victims of carbon dioxide poisoning, and doubt must remain that all the findings can be attributed to this gas alone.

Carbon dioxide has been tried as a human and experimental anaesthetic agent[12,13] and used in the treatment of mental withdrawal states[14] in mixtures of air or oxygen. A mixture of 30% carbon dioxide in air induces anaesthesia, but adverse effects such as convulsions preclude its use in surgery.[15] We speculate that the states of prolonged coma reported by the

survivors were caused by anaesthetic concentrations of carbon dioxide being formed as the gas mixed with air during its flow into the valleys and that because it was a calm night the mixture remained suspended in topographical hollows until dispersed by winds or heat from the sun. As in carbon dioxide narcosis in patients with respiratory disease, spontaneous recovery and return to consciousness would be expected once the arterial pH reverted to normal.[16]

Some of the skin lesions—for example, those over the cheek bones—may have been caused by a combination of pressure and hypoxia from lying comatose on a hard surface,[17] which would also account for the transient nerve palsies. Falling near fires (which would have been extinguished by carbon dioxide) may also have occurred, but we could not find such obvious explanations for the widespread erythema or the bullae noted. Erythematous lesions which may progress to intraepidermal or subepidermal vesicles or bullae with sweat gland necrosis have been reported in coma due to carbon monoxide poisoning[18,19] and drug intoxication, particularly with barbiturates[20-22]; the mechanism of their development is conjectural, though pressure, hypoxia, and a direct toxic effect have all been cited. Theoretically carbon monoxide is not likely to have been a substantial component of the gas, and as it is no denser than air at normal temperature, it would not have flowed into the valleys. The degree of blistering also was not typical of the smaller, more discrete lesions usually reported in carbon monoxide poisoning.

The pathophysiology of coma induced by carbon dioxide has not been described, but carbon dioxide increases cerebral blood flow in the short term[23]; the remarkable absence of clinical central nervous system injury in survivors suggests that it might have had a protective effect in prolonged coma. The effect of high concentrations of carbon dioxide on thermoregulation in humans is uncertain, but it might well eliminate shivering and peripheral vasoconstriction. As the ambient night temperature in the area in August is around 15°C,[24] some degree of hypothermia is likely to have occurred, and this may have been a factor in the erythema[25] as well as contributing to mortality. Unlike human skin, animal skin does not blister, so that the absence of bullae on the dead cattle is of no relevance.

On their arrival at the scene of the Lake Monoun incident at 6 30 am rescuers observed a misty cloud which did not disperse until three to four hours later, when they examined the bodies and noted erythematous and bullous skin lesions.[4] Most of the victims had been overcome soon after 3 am on a 200 m stretch of road near the lake. Six months after the event Sigurdsson *et al* found that carbon dioxide with a small amount of methane still effervesced from deep water samples, and they concluded that carbon dioxide had been the lethal gas.[4]

In the incidents at Lake Nyos and Lake Monoun the possibility that other gases and toxic chemicals in addition to carbon dioxide were released cannot definitely be excluded. Le Guern *et al* believe that a volcanic eruption was the cause of the gas release at Lake Nyos,[5] but this has been strongly disputed by those who favour a limnological hypothesis for both events.[26] In that hypothesis carbon dioxide from an underlying volcanic source built up slowly over time in the lower layers of the two lakes and was released in a sudden degassing of the stratified waters. Both mechanisms, however, may have been concerned if a volcanic event had triggered the degassing.

Because of the remoteness of the areas where these incidents occurred and local cultural factors detailed pathological and epidemiological studies were difficult or impossible. For example, despite the apparently rapid and complete recovery of the survivors, subclinical neurological damage with cognitive impairment may have resulted from asphyxia, but it was not practicable to investigate this further. After a catastrophic gas release, investigations should be begun at the scene and in hospital immediately, with coordinated epidemiological, toxicological, and pathological studies of the dead and survivors. Acidic volcanic gases can be distinguished from carbon dioxide at necropsy, as they cause severe inflammation of the airways and pulmonary oedema. Inhalation of carbon monoxide and nitrogen oxides produces carboxyhaemoglobinaemia and methaemoglobinaemia, respectively. Raised concentrations of sulphide ion in blood or thio compounds in urine are detectable after exposure to hydrogen sulphide[27,28]; fluoride concentrations in urine may reflect exposure to hydrogen fluoride. Any of these gases might be emitted in a volcanic eruption. Histopathological examination of the skin and biochemical analysis of the bullae fluid would help determine the cause of the dermal lesions. Observations on injury to animals and vegetation and damage to dwellings and the environment in general should be correlated with the effects found in humans. Further description of the investigations required is beyond the scope of this paper, but an outline approach for volcanic eruptions is given elsewhere.[29]

Future studies at Lake Nyos may clarify understanding of the mechanisms concerned in the gas release there, including the feasibility of monitoring for future devastating releases. Engineering methods for safely lowering the level of the lake or degassing its lower layers have been proposed as preventive measures.[30] The catastrophes at Lake Nyos, Lake Monoun, and Dieng, Indonesia, point to large scale emissions of carbon dioxide as a newly recognised hazard in volcanic areas. Gas releases on the scale of these events (the amount of gas from Lake Nyos may have exceeded a quarter of a million tonnes) may have occurred elsewhere, but unless heavy loss of life had ensued they would go unrecorded and leave no geological trace. With the growth of populations in volcanic areas the threat of future catastrophes due to gases from either volcanoes or crater lakes must be considered by emergency planners, even though such events are seemingly rare and difficult to predict.

We thank Professor L Kaptué and Dr G Ngufor for their collaboration and Dr S J Freeth for fig 1. Professor A Gresham and Dr G Park provided valuable insights and commented on an earlier draft of this paper. We are also indebted to the following for their advice: Dr K J Collins, I Hymes, A Newman Taylor, R Pye, T Shallice, and I Wilkinson; Professors W R Keatinge and C McDonald; Father F ten Horn; and Mr D Zeitlyn. We thank the Cameroon government; the Overseas Development Administration Disaster Unit; the British Embassy, Yaoundé; and the British Red Cross Society for their support.

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(Accepted 8 March 1989)

Profile of the GMC

Overseas doctors: diminishing controversy

Richard Smith



Fifteen years ago anxiety over the standard of overseas qualified doctors was one of the factors that led to the Merrison inquiry into the regulation of the medical profession.[1] At the same time many overseas doctors thought that the General Medical Council gave them a raw deal and resented that they were not better represented on the council. Now there is less anxiety over the standards of overseas doctors registered by the council but slowly growing concern about the number of doctors from the European Community who are coming to Britain to practise. The concern remains, however, that overseas doctors are underrepresented on the council and overrepresented among those appearing before the professional conduct committee,[2,3] and in a recent session of the committee that I attended seven of the eight doctors appearing had qualified overseas.

Overseas committee

The overseas division of the GMC is its largest, with a staff of 53. Accounting for almost a third of the council's expenditure (over £1m annually), the division is self financing—raising its money from fees for limited registration and for the test set by the Professional and Linguistic Assessment Board (PLAB). The division is overseen by the overseas committee, which has 25 members (including two lay members) and meets twice a year. Most of the work is done by two subcommittees—the F committee, which supervises applications from overseas doctors for full registration, and the L committee, which oversees applications for limited registration.

One of the council's busiest divisions, it is accommodated in cramped conditions round the corner from the headquarters. Its work was expected to diminish as it became more difficult for overseas doctors to come to Britain because of increases in home graduates and changes in registration and visa requirements, but this has not yet happened (fig 1).[4] The division continues to receive roughly 10 000 letters each year from overseas doctors interested in coming to Britain; most are eligible for limited registration if they take the PLAB test; a few (mostly from American medical schools) are eligible for limited registration without taking the test; some are eligible for full registration; and a few are ineligible because their qualifying examination is not recognised.

Two tiers of registration

The Merrison committee produced objective and subjective evidence to support its assertion that "there are substantial numbers of overseas doctors whose skill and the care they offer to patients fall below that generally acceptable in this country, and [that] it is at least possible that there are some who should not have been registered."[1] It then went on to criticise the GMC for relaxing its standards to admit much needed overseas graduates into Britain: "We believe that the present unsatisfactory situation is principally to be attributed to a willingness on the part of the GMC to allow its duty as the protector of medical standards to be compromised by the manpower requirements of the NHS."[1] That the council was lax in its standards when overseas graduates were desperately needed and is now harsh when they are not contributes to the impression among some overseas graduates that the GMC exercises a form of institutionalised racism. It also illustrates how the council may have put the health service's interest before the public interest.

Despite criticising the GMC the Merrison committee largely accepted the council's proposals for improving the system for registering overseas doctors, and the system proposed is essentially that which prevails today—a two tier system. Interestingly, the overseas committee would like to introduce a one tier system because it feels that the present system is unfair and over elaborate. Any change would require legislation.

Full registration

Full registration may be granted to graduates of 23 medical schools in Australasia, Hong Kong, Malaysia, Singapore, South Africa, and the West Indies (fig 2). To achieve full registration the doctors also have to be of "good character" and to have completed the equivalent of preregistration house jobs. Graduates from Australasian universities account for most of the overseas graduates granted full registration. (Since October 1987 British doctors wanting to practise in New South Wales have had to take a professional and

British Medical Journal, London WC1H 9JR
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Br Med J 1989;**298**:1441-4

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by
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March 23, 2022

This report is developed from information clearly in the public domain. The views expressed in this document represent the opinion of the author.

I. Introduction

Accufacts Inc. ("Accufacts") was asked to review and comment on various aspects related to carbon dioxide transmission pipeline safety and federal pipeline safety regulations within the U.S. In recent years there has been considerable discussion about how to address carbon dioxide emissions and global warming through carbon capture, utilization, and sequestration (aka "CCUS" or "CCS"). CCS efforts are intended to help mitigate climate change by capturing carbon dioxide emissions both before and after they are released to the atmosphere and permanently storing such material deep in underground geological structures.

The federal Pipeline Safety Act ("PSA") directs the U.S. Department of Transportation ("DOT") to issue detailed safety standards with regard to the design, construction, operation, and maintenance of CO_2 pipelines.[1, 2] In turn, the DOT has delegated its authority to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The PSA's broad mandate is supplemented by detailed federal regulations.[3] The PSA expressly prohibits state and local regulation that interferes with or supplements federal safety standards for interstate pipelines.[4] States meeting certain conditions may supplement federal pipeline safety regulation on their intrastate pipelines as long as such state regulations are not in conflict with federal pipeline safety regulations.

The U.S. has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,150 miles, out of a total 229,287 miles of hazardous liquid transmission pipelines within the U.S.[5] The vast majority, if not all, of these CO_2 existing pipelines are driven by enhanced oil recovery ("EOR") efforts that increase oil production utilizing CO_2 in a supercritical state. Most of this supercritical state CO_2 comes from high pressure higher purity natural underground source domes. It is an excellent solvent for EOR efforts, but the CO_2 must be injected into oil fields as a supercritical fluid.

CCS efforts are driven by an entirely different purpose such that CO_2 used for CCS could be shipped as a gas or a non-supercritical liquid. However, current federal safety regulations regulate only pipelines that transport supercritical CO_2 containing over 90% carbon dioxide molecules, and not pipelines that ship CO_2 in these other lower concentrations or forms, leaving a large regulatory gap. Moreover, even the regulations for supercritical CO_2 pipelines are incomplete or inadequate and place the public at

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[1] 49 U.S.C. § 60101 *et seq*.
[2] 49 U.S.C. § 60102(a) and (i).
[3] 49 C.F.R. Part 195.
[4] 49 U.S.C. § 60104(c) ("A State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation.")
[5] PHMSA reporting database, "Hazardous Liquid Pipeline Miles and Tanks," as of January 31, 2022 for CO_2 commodity at: https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=Infrastructure.

great risk, especially from the tens of thousands of miles of CO_2 pipelines that may be driven by CCS efforts.[6]

A flurry of multibillion dollar CO_2 pipeline proposals have recently been announced, likely driven by enhanced tax credit incentives provided by Internal Revenue Code § 45Q.[7, 8, 9] Congress provided these enhancements in the Bipartisan Budget Act of 2018, and expanded by the Infrastructure Investment and Jobs Act of 2021 ("Acts of 2018 and 2021").[10] As intended, these laws accelerated CCS and CO_2 pipeline development efforts, because they make such credits more available and valuable to certain generators of CO_2 emissions and require projects to start construction by January 1, 2026.[11] Since most carbon dioxide emitters are likely considerable distances from suitable deep, permanent underground storage sites, it is understandable that CO_2 transmission pipelines may be needed between emitters and these storage sites. If CO_2 pipeline mileage increases as projected, the CO_2 pipeline network could soon rival the existing oil and natural gas pipeline networks in size and complexity. PHMSA would be faced with the greatest and fastest pipeline expansion in the history of the U.S. pipeline industry, and many of these pipelines could threaten the safety of countless individuals and communities.

This report is intended to increase regulator and public awareness of the regulatory challenges posed by this proposed massive expansion in CO_2 pipeline mileage and the unique safety risks of transporting CO_2, especially in its supercritical state. It focuses on a higher-level review of the more technical pipeline safety matters, based on decades of pipeline safety experience including pipeline failure investigations, process engineering and process safety management practice, as well as years of experience in processing and handling many tons of liquid CO_2. This report also makes specific recommendations for improvements in federal pipeline safety regulations needed to fill regulatory gaps and ensure public safety. The proposed CO_2 pipeline boom presents

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[6] For one perspective see what I would call a planning study from Princeton University, "Net-Zero America - Potential Pathways, Infrastructure, and Impacts," Final Report, October 29, 2021, pp. 212 – 219 of 348, indicating a possible need of over 60,000 new miles of CO_2 pipelines by 2050.

[7] Des Moines Register, "What we know about two carbon capture pipelines proposed in Iowa," https://www.desmoinesregister.com/story/money/business/2021/11/28/what-is-carbon-capture-pipeline-proposals-iowa-ag-ethanol-emissions/8717904002/, Nov. 28, 2021.

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[9] S&P Global Platts, "Oil producer Denbury plans CO_2 storage hub in southern Alabama." https://www.spglobal.com/platts/en/market-insights/latest-news/energy-transition/020822-oil-producer-denbury-plans-co2-storage-hub-in-southern-alabama, 2/8/2022.

[10] 26 U.S.C. § 45Q.

[11] I.R.C. § 45Q.

PHMSA with an unprecedented challenge; hopefully, this report will help PHMSA rise to this challenge.

II. A brief history of U.S. federal CO_2 pipeline safety regulation

PHMSA and its predecessor agencies, such as the Office of Pipeline Safety, have historically relied on more prescriptive minimum safety approaches. In the past several decades federal minimum pipeline safety regulations have, by the industry's lobbying, shifted to more "performance-based" approaches that rely heavily on certain industry standards or recommended practices, some of which are incorporated by reference into federal pipeline safety regulation.[12] This industry driven shift can result in changes in pipeline safety regulations without proper public input. A prime example may be in the development of CO_2 transmission pipeline safety regulations that historically have been a very small percentage of overall transmission pipeline mileage in the U.S. This country may be facing a significant increase in CO_2 transmission pipeline mileage without appropriate pipeline safety regulatory development or enactment, leaving the country and the public ill prepared for a tsunami of CO_2 pipeline construction.

Congress, in Section 211 of the Pipeline Safety Reauthorization Act of 1988, required that the DOT regulate carbon dioxide transported by pipeline facilities. Part of this concern was driven by a 1986 natural carbon dioxide release event in Lake Nyos, Cameroon spanning many miles with over 1,700 fatalities, underscoring the dangers and possible consequences of CO_2 releases.[13] On July 12, 1991, federal regulators issued a minimalist final rule that mainly added the words "and carbon dioxide" to existing federal minimum pipeline safety regulations developed for hazardous liquid petroleum pipelines (49CFR§195). It opted to not issue standards specifically applicable to supercritical CO_2 pipelines due to the small number of already existing and anticipated CO_2 pipelines. Even though the situation is about to change dramatically, PHMSA has not proposed to review and overhaul its CO_2 pipeline standards, such that these limited regulations are still in effect today.[14] As a result, many of PHMSA's regulations no longer are adequate to protect public safety.

For example, under federal regulations "carbon dioxide" is defined as follows:

> "Carbon Dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[15]

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[12] 49CFR§195.3 What documents are incorporated by reference partly or wholly in this part?

[13] Federal Register / Vol. 56, No. 113 / Wednesday, June 12, 1991/Rules and Regulations, Research and Special Programs Administration (RSPA), DOT, Docket No. PS-112, Amendment 195-45, RIN 2137-AB72, 49CFR Part 195, "Transportation of Carbon Dioxide by Pipeline," final rule.

[14] *Ibid*, p. 26924.

[15] 49CFR§195.2 Definitions.

The above definition is clearly not appropriate to deal with CCS CO_2 pipelines, nor is that its intent as demonstrated further in this report.

Existing U.S. CO_2 transmission pipelines are primarily located in sparsely developed or more rural locations and, as mentioned previously, involve approximately 5,150 miles moving CO_2 mostly from natural underground sources/domes to EOR projects. The current definition of "carbon dioxide" does not include pipelines that transport supercritical carbon dioxide streams in which CO_2 makes up less than 90 percent of the stream. It also excludes pipelines that transport CO_2 as a non-supercritical liquid or gas. In 1991, there were only a very limited number of pipelines transporting CO_2 in these other forms that apparently didn't justify the need for federal regulation, which is not the case now.

In 2011, Congress, in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 15, mandated that the Secretary of Transportation "prescribe minimum safety standards for the transportation of carbon dioxide by pipeline in a gaseous state." As a result, PHMSA issued a report in early 2015 entitled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State."[16] Unfortunately, PHMSA never issued new regulations for transportation of CO_2 as a gas.

Thus, PHMSA currently has no regulations applicable to pipelines transporting CO_2 as a gas, liquid, or in a supercritical state at concentrations of CO_2 less than 90 percent. This regulatory gap means that current federal pipeline safety regulations are clearly inadequate because CO_2 pipeline companies could develop CO_2 gas and liquid pipelines that fall outside of this narrow federal rule. The definition of "carbon dioxide" should be modified so that all CO_2 transmission pipelines are regulated by federal law and held to appropriate minimum safety standards. Otherwise, CO_2 pipelines could be designed, constructed, operated, and maintained with no federal or state oversight.

III. CO_2 transmission pipelines can take on three basic forms

CO_2 transmission pipelines can be designed to transport carbon dioxide either as a supercritical state fluid, a liquid (aka in a subcritical or chilled state), or as a gas. Within the industry the term "dense phase" is often used to label CO_2 pipelines operating in either a supercritical state fluid or in a liquid phase as explained below. It is odd that the proposed new CO_2 transmission pipeline applications recently reviewed have not clearly stated in what phase they are designed to operate, their temperature ranges, nor their quality requirements.[17] The key characteristics of supercritical, liquid, and gaseous CO_2 transmission pipelines are summarized below.

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[16] PHMSA report dated February 2015, posted to the 2016 docket under PHMSA-2016-0049-001 at www.regulations.gov.

[17] For example, see Summit Carbon Solutions, "Application to the South Dakota Public Utilities Commission for a Permit for the SCS Carbon Transport LLC (SCS) Pipeline Under the Energy Conversion and Transmission Facility Act – Document Number: SCS-0700-ENV-05-PE-009-A," dated February 7, 2022.

i. Supercritical state CO_2 transmission pipelines

Pure CO_2 has a critical temperature of about 88 ºF (33 ºC) and a critical pressure of approximately 1070 psia, or pounds force per square inch absolute (73 atm). At temperatures and pressures above these critical values, CO_2 is not technically a liquid and instead is in a supercritical state as a dense phase "fluid" or vapor with properties between that of a liquid and a gas. This supercritical fluid will not condense to liquid within the pipeline, as long as the temperature remains above the critical temperature, no matter how high the pressure is increased above the critical pressure. If the temperature along a supercritical state pipeline drops below the critical temperature, part of the fluid will condense to liquid with a higher density than the fluid. If the pressure along a supercritical state pipeline drops below 1070 psia, part of the CO_2 will convert to a gas/liquid mixture depending on the temperature.

The primary reason that the existing 5,000 or so miles of CO_2 pipelines transport CO_2 in a supercritical state is because CO_2 in this state is an excellent solvent having no liquid surface tension. It readily dissolves oil trapped in porous rock. In contrast, CO_2 destined for sequestration could be transported as a gas or liquid, because sequestration does not, as a practical matter, need the CO_2 to be in a supercritical state, and federal law does not require transportation in a supercritical state. In fact, a clever pipeline operator could employ loopholes to avoid federal pipeline safety oversight by PHMSA. Clearly the sources and needs of CO_2 for EOR are not the same as those for the CCS objective, which is to remove CO_2 from the atmosphere.

CO_2 supercritical fluid transmission pipeline operating pressures usually range from 1,200 to 2,200 pounds force per square inch gauge, or psig. The higher pressure is set based on the maximum operating pressure ("MOP") usually related to a pipe specification limit.[18] There are a minor number of CO_2 supercritical state pipelines that have been designed to operate at much higher MOPs (*e.g.*, 3200 psig). Moving CO_2 as a dense phase supercritical state fluid permits the use of pumps along a pipeline instead of compressors that would be needed to move the material if it were a gas. For pipelines, the use of pumps to move higher density fluids requires smaller, less complex, equipment that is more efficient in moving mass along a pipeline than compressors (*i.e.*, pumps are cheaper to build, install, maintain, and operate than compressors). In addition, the higher MOPs of supercritical state CO_2 pipelines permit them to utilize smaller diameter pipe, albeit much stronger pipe, to move the same tonnage of CO_2 as compared to shipment as a gas. In contrast, gas pipelines require larger diameter pipe to move the same tonnage, because they must usually operate at pressures lower than the supercritical pressure (1070 psig), otherwise some of the CO_2 could convert to a liquid

[18] MOP stands for maximum operating pressure for liquid pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MOP within certain limits, under certain situations.

(depending on the temperature along the pipeline) and such liquid slugs would severely damage/destroy the compressors used in gas pipelines.

While there are many cost/efficiency advantages to moving CO_2 in a supercritical state, there is one well known threat associated with supercritical state operation. A CO_2 pipeline operating in a supercritical state can be more prone to pipe running ductile fractures than hazardous liquids or natural gas pipelines. Running ductile fractures are unusual and particularly dangerous fractures that can "unzip" a CO_2 transmission pipeline for extended distances exposing great lengths of the buried pipeline. These extreme rupture forces throw tons of pipe, pipe shrapnel, and ground covering, generating large craters along the failed pipeline. It is well known that CO_2 pipelines operating in dense phase, either supercritical or as a liquid, are particularly susceptible to such running ductile fractures. Although current federal regulations recognize this risk, they do not contain any detailed requirements that specifically identify how to address fracture propagation threats. Though there are various approaches well known in the industry (*i.e.*, pipe steel fracture toughness parameters, usually for new pipe, and/or mechanical arrestors such as valves, thicker/tougher pipe transitions) such approaches should be specifically mentioned in safety regulation.[19] To address this risk, PHMSA should revise federal regulations, especially for supercritical CO_2 pipelines, to specifically mitigate the effects of these fracture propagation forces. The current regulations do not adequately address these CO_2 fracture risks.

ii. Liquid CO_2 transmission pipelines

Subcooled or subcritical state means to transport CO_2 as a liquid that usually requires chilling and/or cooling of the stream slightly below ambient temperatures to assure the pipeline is operated in one phase, that of a liquid. For new pipelines this also may require the use of pipeline insulation, though not always, to reduce temperature increase of the CO_2 along the pipeline, assuring it stays as a liquid. It is important that cooling stay well above the pipe carbon steel brittle transition temperature of approximately - 20 ºF to avoid the threat of catastrophic pipeline rupture. Despite these obstacles, transporting CO_2 as a liquid, basically at its highest density, which is typically about double the density of CO_2 fluid in its supercritical state, allows the pipeline transportation of more tonnage of carbon dioxide with even smaller diameter pipe than a supercritical state operation, as well as lower MOPs. Because the liquid phase operation also has a lower viscosity, a liquid CO_2 pipeline system for a given length can utilize a fewer number of pump stations that can have major advantages over supercritical state or gas pipeline approaches needed to move similar tonnage of CO_2. For CCS objectives, liquid phase CO_2 transmission pipelines additional efficiency over their supercritical state or gas counterparts may justify the additional cooling infrastructure along such

[19] 49 CFR§195.111 Fracture propagation. The regulation states in full: "A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation." Thus, pipeline safety law contains no detailed standards to prevent running ductile fractures leaving much room for misinterpretation.

pipelines. It is worth emphasizing that PHMSA chose to not issue regulations for CO_2 pipelines designed to operate as a liquid, so such pipelines are currently unregulated.

iii. CO_2 gas transmission pipelines

New pipelines designed to move CO_2 as a gas in a transmission pipeline is not likely, given that the system must be operated at lower pressures. For a CO_2 gas pipeline, the MAOP must not exceed approximately 1,000 psig at normal operating temperatures, so that the CO_2 is maintained as a gas and does not convert to a liquid as this could be disastrous for the pipeline's compressors.[20] For an equivalent daily CO_2 tonnage pipeline capacity, the requirement to keep design pressure lower drives such new gas pipeline approaches to much higher pipe diameters than their liquid or supercritical state pipeline alternatives. However, specific situations may exist where existing liquid or larger diameter natural gas pipelines could be "repurposed" into primarily CO_2 gas service.[21] Such change in service, will most likely be highly limited in its pipeline mileage and, in my opinion, should exceed the requirements identified in ADB-2014-04, addressing repurposing of natural gas pipelines or liquid pipelines. For example, an Advisory Bulletin, or ADB, does not carry the force of promulgated pipeline safety regulation but is issued to more quickly alert pipeline operators of PHMSA concerns on certain issues. ADB-2014-04 does not address, nor was it intended to address, the specific additional challenges associated with unique fracture propagation risks associated with CO_2 transmission pipelines as previous discussed. While there are unique situations where nonoperating or underutilized pipelines exist, there are several factors that can make repurposing of such pipelines to CO_2 gas service economically attractive, given the billions of dollars in tax credit incentives associated with CCS under the Acts of 2018 and 2021, and the associated start construction deadline. The critical deadlines to meet tax credit triggers could make timing of such conversions more favorable than routing and construction of new CO_2 pipelines for CCS. Such pipeline conversions would be at much greater risk of failure from CO_2 service than conventional hydrocarbon or new construction CO_2 pipelines, given the unique and increased potential for CO_2 pipeline ruptures from various risks associated with CO_2 operation. Only time will tell, given the economic temptations and timing thresholds, whether such repurposing of an existing transmission pipeline to CO_2 service will prove practical for CCS utilization.

[20] MAOP stands for maximum allowable operating pressure, which is the standard for gas pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MAOP within certain limits, under certain situations.

[21] See DOT PHMSA, Advisory Bulletin, ADB-2014—04, "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service," Docket No. PHMSA–2014–0040, Sept 12, 2014.

IV. CO_2 transmission pipelines pose different risks than traditional hydrocarbon transmission pipelines

Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air, and is an asphyxiant and intoxicant, making CO_2 pipeline releases harder to observe and avoid especially as a released plume spreads and migrates well off the pipeline right-of-way. CO_2 properties differ from those for materials moved in hazardous hydrocarbon liquid or natural gas transmission pipelines. CO_2 pipeline releases significantly increase the possible "affected" or "potential impact" area identified in federal regulations addressing hydrocarbon transmission pipelines upon pipeline rupture release, and CO_2 pipeline ruptures have a greater potential to endanger the public. Current federal pipeline safety regulations do not incorporate these important CO_2 differences to assure safety to the public. Federal pipeline safety regulatory changes are warranted if CO_2 pipeline mileage is to be increased dramatically in the U.S., especially under CCS. CO_2 transmission pipelines have many unique failure dynamics such that a rupture may impact significantly greater geographic areas than hydrocarbon pipelines. In particular, a combination of CO_2 phase/temperature changes may result in explosive pipe release forces as the CO_2 converts to gas. Moreover, CO_2's lack of odor and invisibility means that it may not be possible for citizens and first responders to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. It is important that anyone using such CO_2 detection meters assure that such equipment has been properly calibrated/maintained and users properly trained in their use and limitations. Once a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume. Hydrocarbon pipeline releases that haven't ignited, can usually be detected by unusual smell or sight, which makes CO_2 pipeline releases different and harder to detect by emergency responders or the public.

During a CO_2 pipeline rupture release, multiple phase changes can result not only in the significant lowering of temperature near the pipe failure site, but also the likelihood of solid CO_2 formation (i.e., dry ice). Dry ice particles within the fluid can contribute to fogging in the air and ground around the pipeline release, as well as the formation of dry ice within the pipeline upstream/downstream of the pipe failure site that can impact the rate of release out of a pipe failure. Such dry ice blockage can result in temporary restriction/blockage within the pipe, affecting release rate, especially for smaller diameter transmission pipelines experiencing rupture fracture.

In CO_2 pipelines experiencing smaller, slower rate releases, often called leaks, such as through minor holes or cracks, the resulting lower rate CO_2 rich clouds may disperse/dissipate after a short time. In much larger rate releases, such as pipeline rupture fractures caused from various anomalies or pipeline threats, the resulting release of cold gas and dry ice solid mixtures can be quite dangerous (see video of

DNV rupture failure test of an CO_2 8-inch diameter pipeline).[22] The CO_2 released from a pipeline will be heavier than air, and the high-rate release from a pipe rupture will form cold dense gas fog clouds comprised of dry ice particles and visible water vapor as the humidity in the air condenses from the extreme cooling. Such high-rate releases can produce areas of low visibility from "fog," both from dry ice particles and water condensation. The CO_2 pipeline rupture fog becomes transparent when eventually warmed by the surrounding environment. Upon warming, the CO_2 plume can flow considerable distances from the pipeline unobserved, traveling over terrain, displacing oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline or diesel powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off, and cause pilot lights on furnaces, stoves, and natural gas fireplaces to go out. Oxygen displacement by CO_2 gas can cause asphyxiation of humans and animals, that can lead to death. Further, CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving, using power equipment, or exposed to cold weather. Cooling of a CO_2 release can also impact the rate of release and exacerbate pipe fracture propagation during rupture. Clearly, dispersion modeling for analyzing potential impact areas for CO_2 pipeline failures and their related released gas plumes, must consider the propensity of heavier than air CO_2 gas to displace oxygen and to follow the terrain as terrain factors can play a critical role in evaluating a potential area and receptors that could be affected by a CO_2 pipeline release. It is vitally important to not underestimate the potential distance that a CO_2 pipeline rupture plume can reach and affect, especially in nonlevel terrain. Additional safety margins should be employed in populated areas when using dispersion modeling results for CO_2 pipeline releases.

Before the U.S. is blanketed with a major increase in CO_2 transmission pipeline mileage driven by CCS efforts, substantial changes need to be implemented in federal pipeline safety regulations specifically addressing the unique dangers of CO_2 in transmission pipelines in any phase. CO_2 is not flammable. It doesn't burn or explode/detonate from ignition, so heat radiation is not an issue of concern as in conventional hydrocarbon pipelines. CO_2 can, however, generate similar overpressure "blast" forces upon pipeline rupture (from the high-rate releases associated with pipeline fracture failure, see previous referenced 8-inch CO_2 pipeline rupture test). CO_2 pipeline rupture and resulting rapid "blast like" expansion forces dissipate quickly with distance from the pipeline but can easily extend well beyond the pipeline right of way. The areas potentially impacted by ruptures of oil and gas transmission pipelines are well defined in current federal regulations, which estimate how far liquid hydrocarbon will spread and the blast or burn radius resulting from a natural gas pipeline rupture. The danger zone for human life for hazardous hydrocarbon liquid and natural gas pipeline releases is generally measured in feet, albeit many thousands of feet for larger diameter higher pressure pipelines.

[22] Video of 2013 DNV Spadeadam Research and Testing test experiment of dense phase CO_2 8-inch buried pipeline rupture, https://www.dnv.com/oilgas/laboratories-test-sites/dense-phase-spadeadam-video.html.

In contrast, a CO_2 pipeline's impact area may be measured in miles, not feet. This is likely because:

- CO_2 pipeline ruptures can release many tons of CO_2,
- the compressed CO_2 will expand into gas phase upon pipeline rupture and fill a much larger volume that it did inside the pipe, and
- the CO_2 may not disperse quickly because it is heavier than air, meaning that it will tend to flow toward and settle in low lying areas including ravines, valleys, and basements.

Current federal pipeline safety regulations do not provide any methodology for assessing the hazard zone for CO_2 pipelines or require that pipeline operators adequately address this risk.

V. Impact of impurities on CO_2 pipelines

The amounts and types of impurities in a CO_2 stream can have an impact on pipeline design and approaches. Current CO_2 pipeline regulations, which only address CO_2 pipelines greater than 90% CO_2 concentration compressed to a supercritical state, make no mention as to the level of non-CO_2 impurities such as H_2S, which can be lethal even in very low parts per million concentrations. Also, impurities can affect the range of safe operating pressures. Most of the natural sources of CO_2 for existing pipelines contain CO_2 well above 90%, but this may not be the case for all CO_2 streams captured from industrial facilities. Federal regulation should be modified to adequately regulate CO_2 pipelines used for CCS, and subsequent transportation by transmission pipeline, especially because CCS pipelines may operate differently from those used for EOR. Such federal regulatory improvements should focus on public safety for all forms/phases of CO_2 transmission pipelines. There are some very pure sources of CO_2 emitters, such as ethanol plants and some hydrogen reformers, that emit very high concentrations of CO_2 to the atmosphere that require very little, if any, impurity treatment to prepare for pipeline transportation for CCS.[23] Unlike most of the currently existing CO_2 pipelines whose sources are underground natural gas domes or reservoirs, CSS pipelines may be supplied from various sources where the concentration of CO_2 is quite low and needing concentration, processing, and treatment for contaminant removal before it may be safely transported by pipeline.

There appears to be no transmission pipeline in the U.S. that transports pure CO_2, although there are pipelines that move very high concentrations of CO_2, well above 90%, containing only small levels, of impurities, especially those from natural sources of CO_2. Such CO_2 rich sources can still contain impurities, such as hydrogen sulfide, methane, carbon monoxide, oxygen, nitrogen oxide, sulphur oxide, hydrogen, or

[23] My experience is that purity from such CO_2 specialized emitters can exceed 99.9 % with trace impurities.

water.[24] The types and amounts of impurities in a CO_2 rich pipeline is largely driven by the source of CO_2, and proper operation of associated upstream treatment equipment to assure the material meets pipeline quality specifications, which is not always assured. At relatively low levels of impurities, such as at trace or levels in the lower parts per million, the specific effects of the impurities on the overall stream critical thermodynamic properties (such as enthalpy, entropy, density, and viscosity), are not significantly impacted. However, higher impurity concentrations, such as impurities measured in percentage concentrations should not be ignored as they can impact the critical pressure, but more importantly the critical temperature, such that even a percent or two change in impurity levels can result in unexpected phase change from dense phase fluid to other phases. Such phase changes may impact the system hydraulics, and to some extent the rupture release dynamics should the pipeline fail.

Two impurities that might be possible in CO_2 pipelines merit mention given their unique dangers to pipelines and the public: water and H_2S. CO_2 pipelines are usually made from carbon steel and require special maximum water quality specifications typically measured in the part per million, or its equivalent, that prevents the possibility of free water forming anywhere in the pipeline system. The presence of free water in a CO_2 stream permits the formation of carbonic acid in the pipeline, an acid that has a ferocious appetite for carbon steel. Given the rapidity and unpredictability at which carbonic acid can attack pipelines, prudent CO_2 pipeline operators have voluntarily established maximum water quality limitations for their input streams. Given the risks associated with carbonic acid attack, PHMSA should not leave this critical factor to company discretion, but instead should adopt federal regulations that specify a maximum water quality limitation for CO_2 pipelines.

Hydrogen sulfide, or H_2S, is mentioned here because of a curious item identified in an article related to a supercritical state CO_2 pipeline rupture failure in Mississippi in early 2020.[25] The observations noted in the article by responders of a "green cloud" from the pipeline release, is a possible indication of high levels of H_2S. Further investigation indicates that the source of the CO_2 (Jackson Dome) has levels of H_2S at 5 percent, or 50,000 ppm. In contrast, the Centers for Disease Control and Prevention states that a level of 300 parts per million is "immediately dangerous to life or health."[26] While the H_2S level that transitions into "sour" gas is not defined in federal

[24] For example, see Suoton P. Peletire, Nejat Rahmanian, Iqbal M. Mujtaba, "Effects of Impurities on CO_2 Pipeline Performance, Chemical Engineering Transactions," Vol. 57, 2017.

[25] Dan Zegart Huffpost article, "The Gassing of Satartia," August 26, 2021 at https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f,

[26] https://www.cdc.gov/niosh/idlh/7783064.html. It is my understanding that while a few states have attempted to impose H_2S limits on intrastate pipelines, there is no such federal pipeline safety regulation limiting H_2S on transmission pipelines, even though there are OSHA H_2S limits on workplace workers, much lower than 300 ppm.

pipeline safety regulations, serious questions need to be raised about this specific CO_2 pipeline operation.

For CCS generated CO_2, from fuel combustion emission, an expected source for CCS, H_2S is not a likely contaminant of the stream with trace levels of H_2S in the less than 1 ppm to be expected. Treatment for the removal of water and water quality enforcement control limitations, however, are critical for CCS pipelines transporting CO_2 from combustion sources. Yet, current federal pipeline safety regulations also do not require that this risk be addressed.

VI. Areas needing additional federal pipeline safety focus for CO_2 pipelines

Based on my experiences, the following are my preliminary observations on specific areas where CO_2 pipeline safety regulation improvement efforts should focus.

1. **PHMSA should update the definition of carbon dioxide in current regulation.**
   The current "carbon dioxide" definition incorporated into pipeline safety regulation is driven by EOR and does not or may not apply to all CO_2 pipelines that may be developed for CCS projects. Federal regulations need to be modified to assure that federal standards apply to all CO_2 transmission pipelines that transport CO_2 for CCS projects, including all supercritical, gas, and liquid CO_2 transmission pipelines.

2. **PHMSA needs to identify in regulation the potential impact areas for CO_2 pipeline ruptures.**
   The unique, and potentially very large impact areas for CO_2 pipeline ruptures need to be developed, defined, and promulgated into pipeline regulations. As mentioned previously, these areas are most likely to be measured in miles, not feet.

3. **Specific CO_2 pipeline federal regulations should not be based solely on industry Recommended Practices.**
   Changes in the CO_2 pipeline safety regulation are needed and should be prescribed to avoid misinterpretation or misuse. Recent efforts by many in the industry to rely on more performance-based standards, even those incorporated by reference, have proven ineffective and disastrous. Such industry efforts also remove an important party to pipeline safety regulatory development, the public. Ironically, it is the public that has the most to lose from inadequate pipeline safety regulation if such referenced citations are not clear, relevant, effective, and cannot be enforced in assuring pipeline safety.

4. **PHMSA should specifically identify how to incorporate fracture propagation protection on CO_2 transmission pipelines.**
   Given the differential propensity for CO_2 pipelines to propagate fractures along the pipeline upon rupture, regulations should specifically list pipeline design methods to arrest CO_2 fracture propagation.

5. **PHMSA should mandate the use of odorant injection into CO_2 transmission pipelines.**
   Given the inability to detect or observe a CO_2 pipeline release, it is time to require the use of odorant injection in such pipelines, especially those pipelines that are not in unpopulated areas, to assist the public in identifying dangerous releases.

6. **PHMSA should require CO_2 pipeline operators to update their required procedural manuals related to coordination with local emergency response agencies for CO_2 pipeline ruptures.**
   The major differences and uniqueness of CO_2 pipeline releases compared to hydrocarbon pipelines require that pipeline operators improve the sections of their federally mandated operation, maintenance, and emergencies procedural manuals for emergency response to CO_2 pipeline ruptures.[27] In particular, operators must be required to periodically and fully inform, train, and equip key local officials and emergency responders with regard to special response actions unique to CO_2 pipeline releases. Moreover, upon a rupture, pipeline operators must inform state and local emergency personnel so that they can quickly and adequately protect impacted citizens and themselves.

7. **PHMSA should establish regulations setting specific maximum contaminant impurities for CO_2 pipelines.**
   Given the various sources and the unique risk associated with the introduction of water into a CO_2 pipeline, PHMSA should prescribe the maximum concentration of water allowed in them. This requirement goes well beyond a quality specification given the ability of water to rapidly cause CO_2 pipeline failures in unpredictable ways. Given the wide range of impurity sources for CO_2 streams for CCS, PHMSA should review a full range of limits for all common impurities and consider establishing maximum levels for all impurities that pose a safety risk in federal pipeline safety regulations.

8. **PHMSA should strengthen federal regulations for conversion of existing pipelines to CO_2 pipeline service.**
   It is not clear whether the public interest is best served by CO_2 shipment in existing transmission pipelines converted to CO_2 service. Further, the general conditions of PHMSA's advisory bulletin are not adequate for conversion to CO_2 pipelines. PHMSA should fully investigate the risks of such conversions and issue regulations appropriate to the serious risks that could result from repurposing a pipeline for CO_2 service.

VII. Conclusions

Current federal minimum pipeline safety regulations focus on higher concentration CO_2 pipelines transporting CO_2 in a supercritical state for use in oil production. Such

[27] 49CFR§195.402 and 49CFR§192.605 Procedural manual for operations, maintenance, and emergencies.

regulations are incomplete or in conflict with the intent of CCS, to reduce CO_2 content in the atmosphere to address global warming. Federal pipeline safety regulation concerning CO_2 pipelines need specific changes to address the likely expansion of CO_2 transmission pipeline mileage expected by CCS efforts enhanced by the Acts of 2018 and 2021.

Certain manufacturing processes, such as ethanol and some hydrogen reforming refinery units, produce CO_2 emission that are very pure CO_2, with only trace amounts of contaminants, that are higher priority choices for CCS and associated pipelines, most likely new liquid transmission pipelines, especially under the immense tax credits associated with the Acts of 2018 and 2021. Current federal pipeline safety regulations, however, are not adequate to deal with the additional pipeline risks associated with the expected significant increase in associated CO_2 transmission pipelines under CCS.

The country is ill prepared for the increase of CO_2 pipeline mileage being driven by federal CCS policy. Federal pipeline safety regulations need to be quickly changed to rise to this new challenge, and to assure that the public has confidence in the federal pipeline safety regulations.[28]

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[28] Disclosure: The author prepared this report for the Pipeline Safety Trust but retained full editorial control. The author received compensation from the Pipeline Safety Trust and the Bold Alliance for the preparation of this report.

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Energy Procedia 37 (2013) 791 – 799

Energy Procedia

GHGT-11

Environmental impacts of CO_2 leakage: recent results from the ASGARD facility, UK

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Abstract

The RISCS (Research into Impacts and Safety in Carbon Storage) project is investigating potential environmental impacts of CO_2 leakage. At ASGARD (Artificial Soil Gassing and Response Detection), a fully-replicated facility for controlled injection of CO_2 into soil, investigations have been carried out to determine the effects of elevated soil CO_2 on crops, soil microbiology, soil flux and soil CO_2 concentration.

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Keywords; CO_2 storage, ASGARD, crop stress, CO_2 flux, microbiology

1. Introduction

Carbon Capture and Storage is increasingly seen as a way of combating rising CO_2 concentrations in the atmosphere. Although storage sites will be designed for zero leakage it is important to consider the possible environmental effects in the unlikely event that leakage does occur, for both risk and environmental impact assessments. The potential responses of ecosystems depend on CO_2 concentrations, event duration, the sensitivities of different organisms and external environmental factors [1]. The RISCS (Research into Impacts and Safety in Carbon Storage) project is investigating these issues using the

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Selection and/or peer-review under responsibility of GHGT
doi:10.1016/j.egypro.2013.05.169

University of Nottingham ASGARD (Artificial Soil Gassing and Response Detection) facility. ASGARD applies controlled injection of CO_2 into soil to measure the impacts on crop species of diffuse CO_2 leakage over periods of several weeks to months. The system design is fully replicated and enables monitoring of changes in plant and soil conditions and the testing of CO_2 detection techniques.

2. The ASGARD facility and RISCS experiments

The ASGARD facility is a purpose-built site (location, N52°, 49'60□; W01°,14□60□) for the study of ecosystem responses to elevated soil CO_2 concentrations [CO_2]. CO_2 gas is delivered to as many as 16 field plots via 20 mm (ID) medium density polyethylene gas pipes. The pipes are sealed at the end but perforated over the final 21 cm and are inserted into the ground at an angle of 45º to the vertical so that the gas is delivered into the soil 50 - 60 cm below the centre of each gassed plot. Food-grade, liquid CO_2 is stored in two 200 L cryogenic vessels (BOC, Derby, UK) that are refilled as required from a road tanker. The liquid CO_2 is converted to gaseous form and down-regulated to ~152 kPa for delivery via a single inlet mass flow sensor (Alicat, Tucson, USA) to 16 individual mass flow controllers (Alicat) that regulate the gas flow to individual experimental plots. The mass flow controllers are operated, and the system data logged, by a PC-based control system (TVC, Great Yarmouth, UK).

Fig. 1 shows a general view of part of the ASGARD site. The experimental area was divided by crop type into three blocks of eight replicate 2.5 × 2.5 m plots with additional plots used as test areas. In each block, four randomly selected plots were treated with injected CO_2 gas and four acted as untreated controls. In the experiments described here, CO_2 was supplied to each plot at a constant rate of 1 L min^{-1}. The single point injection scheme generates a distribution of CO_2 in the soil ranging from high concentrations, sometimes above 50%, in the plot centre down to values approaching control levels at the plot edges. This distribution was used to investigate vegetation responses to soil CO_2. For analysis, sampling areas within the plots were zoned into low, medium and high CO_2, corresponding respectively to seasonal average soil concentrations of approximately 2-5%, 5-15% and >15%, as measured across the grid shown in Fig. 2 using a bar-holer and a Geotech GA2000 gas analyser (Leamington Spa, UK).



Fig. 1 The ASGARD site in 2006, showing pasture plots, CO_2 injection tubes (yellow) and gas measurement tubes (black).

2.1. Plant studies

Studies were carried out on a range of crop types to determine the sensitivity of plant types to elevated soil CO_2. Two experimental areas were used during the RISCS project. Pre-existing plots were used in 2010; new blocks of plots were established for RISCS and used in 2011 and 2012. Soil microbiology and detailed soil gas and flux measurements were carried out on a separate block in the old pasture plot area.

A grass/clover mixture was sown in eight plots to determine competition effects caused by differential stress effects on the two plant species. Following plant establishment, CO_2 gas was delivered to four plots from 21st March 2011 to 15th June 2012. Biomass was collected at about six-weekly intervals throughout the growing season by scissor cutting samples within a 20 × 20 cm square across two transects (7 samples) within each gassed plot and across one transect in each control plot (4 samples). Each sample was separated into the two species which were then weighed and dried. The plots were mown immediately following each sampling.

In the remaining plots two different crops were sown in each year: spring-sown barley and oilseed rape in 2010; beetroot and spring wheat in 2011. Seeds were sown in April and allowed to germinate and become established before gas was delivered. Crops were harvested when ripe, or earlier if weather or animal damage dictated. Biomass samples; stem height, dry weight and taken from each crop at harvest.

Root effects were studied by using a minirhyzotron (Bartz, Carpinteria CA, USA) a tube and camera system to count the number and length of roots in oilseed rape, grass/clover and wheat. Two minirhyzotrons were installed at a 45° angle to the vertical in each gassed plot and one in each control plot. They were positioned such that the tube at the South side of the plot passes through a low gas zone and the tube at the East side passes through a high gas zone. The Bartz camera is lowered down the tubes and an image is captured every cm down to a depth of approximately 60 cm. The root images were analysed using Rootracker software supplied by Bartz. Fig. 2 illustrates a plot layout with the measurement locations and infrastructure installed.

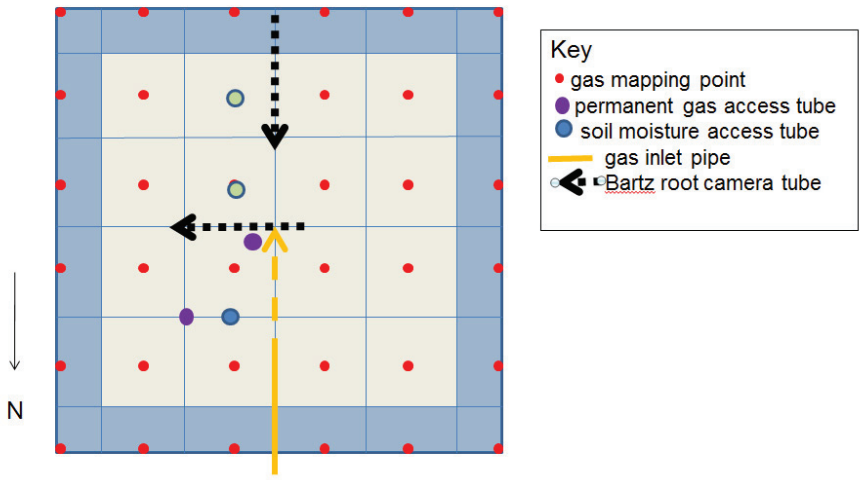


Fig. 2. Plot plan showing measurement locations and plot infrastructure. Samples for microbiological studies were taken in the centre of the squares marked by red circles. The shaded outer zone is a buffer; plant measurements were made in the central 16 squares.

2.2. Soil CO_2 concentration and flux measurements

Routine measurements of soil [CO_2] in each plot were carried out using a GA2000 landfill gas analyser (Geotech, Leamington Spa, UK) attached to the permanently installed gas access tubes (Fig. 1). In addition a continuous flux monitoring station consisting of a Licor LI-8100 system with four accumulation chambers controlled by an automated operating and data logging system was installed across two plots, one gassed, one control. The monitoring chambers were located as shown in figure 3. Within each sampling chamber, CO_2 flux, average [CO_2] over the 2-minute sampling period, humidity, atmospheric pressure and ground-level air temperature were measured, with data collected initially at 5-hour intervals for the first phase (3 - 17 August 2010), then at one-hour intervals for the second phase (17 August - 1 September 2010). An additional monitoring station (designed and constructed by the University of Rome) which continuously measured the concentration of CO_2 and CH_4, temperature, and atmospheric pressure at three separate points using remote probes was deployed to monitor the temporal variability of CO_2 on the ground surface and in the shallow soil of gassed and non-gassed plots, to determine CO_2 concentration ranges and exposure times for use in site modelling and biological studies, and to compare with other environmental parameters to better understand gas migration and accumulation processes. Probes 0 and 2 were buried underground to monitor gas concentrations in the unsaturated zone, with probe 2 placed near the centre of a gassed plot and probe 0 placed near the centre of an adjacent, non-gassed plot (fig. 3). Probe 1 was placed on the ground surface near the centre of the gassed plot, above probe 2, to monitor atmospheric concentrations at the soil-air boundary.

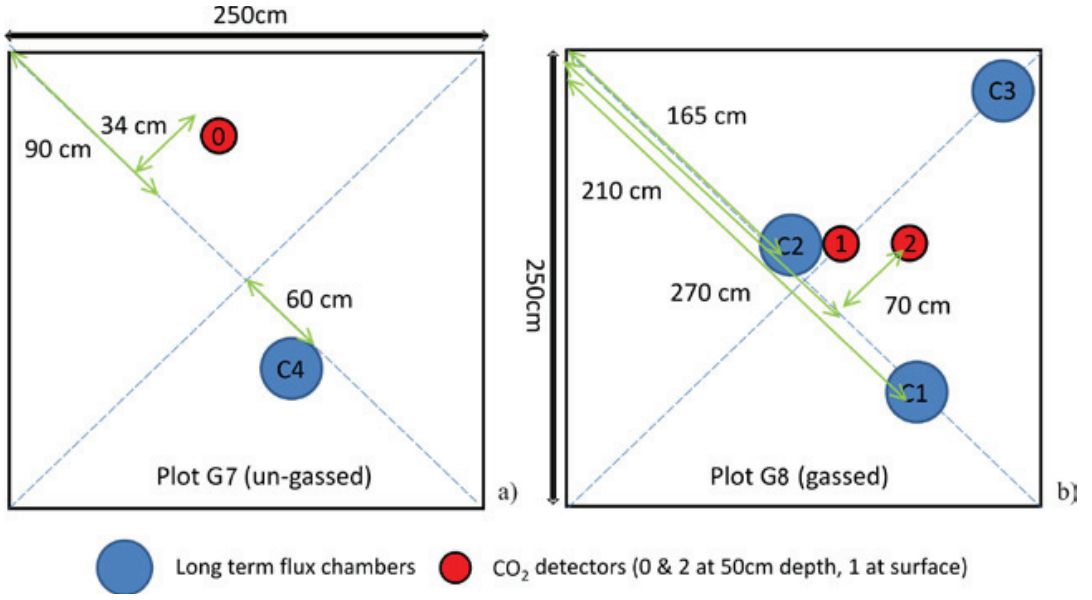


Fig. 3. Schematic map showing the spatial distribution of the deployed gas concentration and flux units, with the un-gassed plot on the left and the gassed plot on the right. The map is orientated with North at the bottom edge. The larger blue circles refer to the flux chambers and the smaller red ones to the probes. Probes 0 and 2 are at 50 cm depth while probe 1 is on the ground surface.

2.3. Microbiological studies

Studies in the pasture plots determined the effects of elevated levels of CO_2 on soil microbiology. Samples were taken from the centre of the 0.5 m squares (outlined with red dots on figure 2) using a hand held "Dutch" auger at depths of 15 - 30 cm, 45 - 50 cm and 65 - 70 cm. Epifluorescence microscopy was used to determine total cell counts and Adenosine Triphosphate (ATP) assay used for evaluating microbial activity [2]. To study the influence of induced CO_2 on important microbial metabolic pathways the aerobic methane oxidation and anaerobic methane and CO_2 production were determined both with and without oxygen by incubating soil samples at 20°C in 15 ml glass bottles with 3 g soil and in 119 ml glass bottles with 10 g soil. The glass tubes were sealed with butyl-rubber stoppers and screw caps/aluminium crimp caps, flushed with oxygen in case of the aerobic methane oxidation and nitrogen in case of the anaerobic methane and CO_2 production [3][4][5]. For inhibition of acetate dependent methanogenesis, 1% methyl fluoride (CH_3F) was added. For investigation of aerobic methane oxidation, 1% methane was supplemented. Headspace samples were analysed for methane and CO_2 by GC-FID (SRI 8610C, SRI Instruments, USA) gas chromatography equipped with a methanizer [6].

3. Results

3.1. Plant studies

Symptoms of plant stress are seen rapidly with visual changes to the vegetation observed within seven days of delivering CO_2 gas to the plots. Barley, wheat and grass leaves turned yellow and spring-sown oil seed rape and beetroot leaves turned purple within 7 - 10 days. Biomass changes were seen in all plants but to different extents. In grass/clover the mean total biomass collected over the season shows that in high gas zones the biomass of both grass and clover decreased, but whereas the clover biomass decreased by 79%, the grass decreased by 42%. Clover biomass was greater than that of grass in the control, low and medium CO_2 zones (fig. 4).

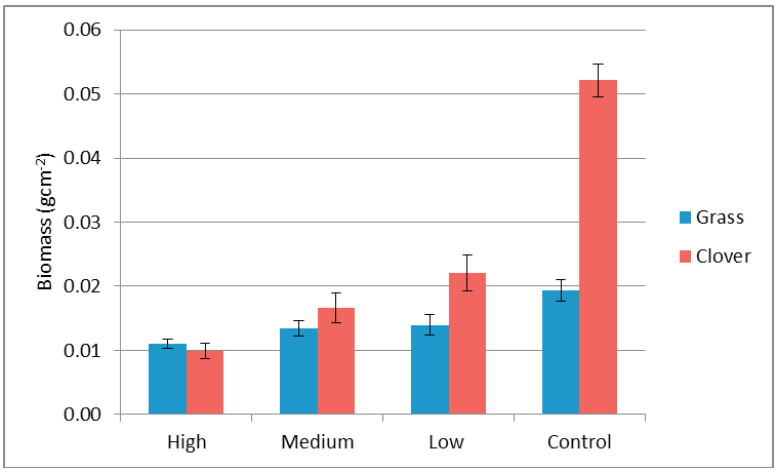


Fig. 4. Change in biomass (g cm^{-2}) of grass and clover growing in soil with high, medium and low concentrations of CO_2, collected between March and October 2011.

Rye grass, a monocotyledon, showed greater tolerance to high soil [CO_2] than clover, a dicotyledon. Similar results were found by Al-Traboulsi [7] who found that maize (monocotyledon) was more tolerant than field bean (dicotyledon). Decreases in biomass were also seen in spring sown barley and oilseed rape. In both plants the crop was shorter in the area of highest soil [CO_2]: oilseed rape was 30 cm shorter, barley was 10 - 20 cm shorter, than in the controls. In both barley and oilseed rape there was a 20% reduction in biomass but whereas barley grain number was reduced by 30% there was no significant reduction in the number of oilseed rape pods. Beetroot showed no significant difference in beet number, biomass or size but leaf biomass was reduced by up to 25% in areas of high [CO_2]. It is possible that the beet storage organs acted as a buffer so that decreased leaf biomass was not reflected in tuber size. Also, the roots of beetroot are very shallow and so may not have been affected by the higher [CO_2] at depth. These results show that high soil [CO_2] affects crops in different ways as in this instance the monocotyledon was affected more than the dicotyledon.

The root imagery shows that in oilseed rape the total number of roots in the control plots increased with time with most roots being present in the 10-19cm depth range (fig. 5). The number of roots counted before CO_2 injection commenced in the gassed plots was similar to the control plots. In the minirhyzotron at the south of the plot, the surface roots are subject to lower [CO_2] and here the number of roots in the 10 - 19 cm range were similar to the control plots, but towards deeper levels the roots are subject to higher [CO_2] and there were fewer roots as depth increased, with very few roots below 60 cm. The number of secondary roots at depth also decreased. In the minirhyzotron at the East of the plot which passes through the highest levels of soil [CO_2], there was an increase in the number of roots in the 10-29 cm range when compared to the control plots, but a decrease in the number of roots at greater depths. There were fewer secondary roots at all depth ranges.

In the grass/clover plots, it was not possible to differentiate the two species in the root images but the mean number of roots in the high gas zone (East tube) was generally greater than in the control (fig. 5). At depth there were fewer roots in the high gas zones. The results suggest that in some instances, the effect of soil CO_2 may be to stimulate the generation of roots.

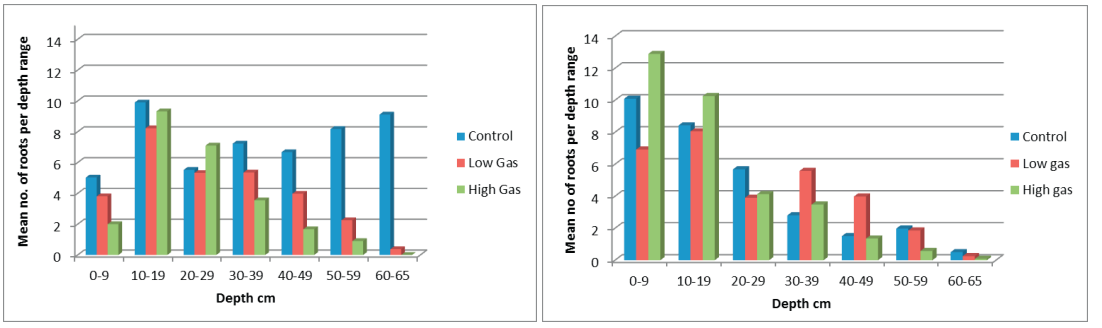


Fig. 5. Mean number of roots per depth range for oilseed rape (left) after 26 days gassing and grass/clover (right) after 67 days gassing.

3.2. Soil CO_2 concentration and flux measurements

Seasonal average [CO_2] in the permanent access tubes located 15 cm from the plot centre was 57% (±2% SE) and 44% (± 2% SE) in oilseed rape and barley plots respectively. In the tubes located 70 cm

from the centre, the corresponding values were 16% (±1%) and 4% (±0.4%). Control plot concentrations were 0.7 % (±0.02%, maximum 1.8%) and 0.8 % (±0.03%, maximum 3.4%) respectively.

Continuous monitoring of CO_2 concentrations in the shallow soil and on the ground surface using the three deployed probes has highlighted the variability of gas migration and accumulation as a function of meteorological parameters, gas supply, and unsaturated zone permeability. Data from the two buried probes showed a lateral interconnection between the gassed and non-gassed plots, with start-up and shut-down of gas injection flow resulting in clear responses in both probes that were typically offset by about 6 - 8 hours. Heavy rainfall events were seen to cause accumulation of CO_2 in the probe buried above the injection point, whereas low atmospheric pressure appeared to induce reduced [CO_2] in both buried probe locations possibly due to an increased flux out of the soil. Winter data appear to show accumulation due to a soil freezing event, with a rapid release to the atmosphere in the subsequent thaw. At the probe placed on the ground surface, a strong negative correlation was seen with wind speed, such that low wind conditions allowed accumulation of the denser-than-air CO_2 within the plant canopy while even light winds resulted in rapid and efficient mixing. This is illustrated in

Fig. , where these two parameters are plotted over a 2 week period. The diurnal nature of the wind patterns are clearly visible, with low wind during the night and higher winds during the day due to ground heating. As a result, higher CO_2 concentrations occurred at night (i.e. when photosynthesis is not occurring); this relationship can be quite sensitive, as wind speed minima near 4 knots in the first half of the period resulted in concentrations on the order of 0.7%, whereas winds closer to 1 knot (for longer periods) in the latter half yielded CO_2 concentrations as high as 2%. This diurnal cycling was most evident during the more meteorologically stable summer period, as major weather systems during the winter tended to make the winds stronger and more variable. Results from both buried and surface probes illustrate the variability of CO_2 concentrations even with a constant injection rate, and thus these results (concentration ranges, length of time at a given concentration, time of day for a given concentration) must be taken into account for accurate modelling of the impact of CO_2 leakage on physiological processes.

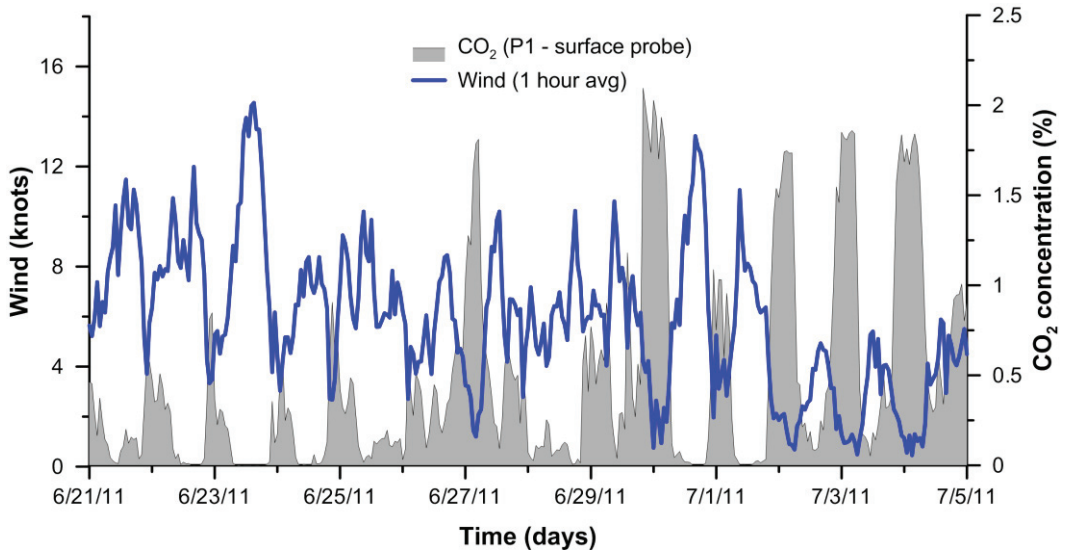


Fig. 6. Negative relationship between wind speed and CO_2 concentration on the ground surface

3.3. Microbiological studies

Previous work in the pasture plots has shown that in ungassed plots bacterial numbers fluctuate between 10^5 and 10^6 bacteria g^{-1} (wet weight) at the 15 – 30 cm depth sample, and that populations declined with depth by about one order of magnitude [2]. This was also reflected in ATP concentration. However, the bacterial numbers in 2010 did not decline with depth and varied between 5×10^5 and 1.5×10^6 bacteria g^{-1} at all depths. However, ATP concentration did decline showing that, although bacteria were present, they were relatively inactive. In 2006, bacterial numbers in the same gassed pasture plot declined from 1.9×10^6 to 2×10^4 bacteria g^{-1} during the three month period of gassing. This same observation was also made in 2010 when the numbers of bacteria in the gassed pasture plots also declined by one order of magnitude during the gassing period, suggesting that gassing soil with CO_2 impacts on microbial populations. By April 2011 numbers had declined to ~5×10^5 bacteria g^{-1} near the centre of the gassed plot where CO_2 soil concentrations were above 30%.ATP concentrations for both gassed and ungassed plots were also very low at this depth. In October 2011, ATP concentrations again varied with a decline of one order of magnitude between control and gassed plots (where soil [CO_2] reached as high as 79%).

Increasing rates of methanogenesis and decreasing rates of methane oxidation at high CO2 concentrations were demonstrated in the gassed plots. CO_2 production rates, which are an important indicator for microbial activity, showed decreasing trends under elevated CO_2 concentrations. Analysis of the microbial community composition by quantitative real time polymerase chain reaction showed alterations in microbial abundances under CO_2 influence with decreasing bacterial and archaeal DNA copy numbers. Variations in the microbial activity as well as in the microbial community composition depending on CO_2 concentration, seasonal variations and depth layers were observed.

4. Conclusions

Studies at the ASGARD facility have shown that elevated concentrations of soil CO_2 have a clear damaging effect on both the soil microbiology and vegetation growing in soil contaminated with high CO_2 concentrations. The extent of the effect depends on the concentration of the CO_2 and the type of vegetation and can affect competition between species in mixed canopies. It had been thought that dicotyledons were more susceptible than monocotyledons but studies at ASGARD have shown that this is not always the case. Continuous monitoring of CO_2 concentrations in the shallow soil and on the ground surface using *in-situ* probes has highlighted the variability of gas migration and accumulation as a function of meteorological parameters, gas supply, and unsaturated zone permeability.

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Acknowledgements

RISCS is funded by the EC 7th Framework Programme and by industry partners ENEL I&I, Statoil, Vattenfall AB, E.ON and RWE. R&D partners are BGS, CERTH, IMARES, OGS, PML, SINTEF, University of Nottingham, Sapienza Università di Roma, Quintessa, CO_2GeoNet, Bioforsk, BGR and ZERO. Four R&D institutes outside Europe participate in RISCS: CO_2CRC from Australia, University of Regina from Canada and Montana State and Stanford Universities from the USA.



Illustration by Hokyoung Kim for HuffPost

The Gassing Of Satartia

A CO2 pipeline in Mississippi ruptured last year, sickening dozens of people. What does it forecast for the massive proposed buildout of pipelines across the U.S.?

By Dan Zegart
August 26, 2021

It was just after 7 p.m. when residents of Satartia, Mississippi, started smelling rotten eggs. Then a greenish cloud rolled across Route 433 and settled into the valley surrounding the little town. Within minutes, people were inside the cloud, gasping for air, nauseated and dazed.

Some two dozen individuals were overcome within a few minutes, collapsing in their homes; at a fishing camp on the nearby Yazoo River; in their vehicles. Cars just shut off, since they need oxygen to burn fuel. Drivers scrambled out of their paralyzed vehicles, but were so disoriented that they just wandered around in the dark.

The first call to Yazoo County Emergency Management Agency came at 7:13 p.m. on February 22, 2020.

“CALLER ADVISED A FOUL SMELL AND GREEN FOG ACROSS THE HIGHWAY,” read the message that dispatchers sent to cell phones and radios of all county emergency personnel two minutes later.

First responders mobilized almost immediately, even though they still weren't sure exactly what the emergency was. Maybe it was a leak from one of several nearby natural gas pipelines, or chlorine from the water tank.

through the hills above town, less than half a mile away. Denbury Inc, then known as Denbury Resources, operates a network of CO2 pipelines in the Gulf Coast area that inject the gas into oil fields to force out more petroleum. While ambient CO2 is odorless, colorless and heavier than air, the industrial CO2 in Denbury's pipeline has been compressed into a liquid, which is pumped through pipelines under high pressure. A rupture in this kind of pipeline sends CO2 gushing out in a dense, powdery white cloud that sinks to the ground and is cold enough to make steel so brittle it can be smashed with a sledgehammer.

Even Durward Pettis, a contract welder for Denbury and chief of the local Tri-Community Volunteer Fire Department, didn't figure out that the mystery fog was CO2 for a full 15 minutes. He'd directed first responders to set up three roadblocks to prevent traffic from entering the area. But it wasn't until 7:30 p.m. that word went out that they'd need self-contained breathing apparatus, or SCBA, to enter Satartia and evacuate the town's 42 residents, many of them elderly, and about 250 others who lived just outside town. By then, rescuers and residents were already in motion, fleeing the gas or evacuating others.

Even once Pettis figured it out, none of the sheriffs' deputies and volunteer firefighters had any emergency training in CO2 leaks. Neither did staff at two area hospitals, which had detrimental consequences for gas victims, according to interviews with many of the 49 who were hospitalized.

"It was bad enough that I thought my mama wouldn't make it, and she still has trouble breathing," said Army veteran Hugh Martin, who fled Satartia in a pickup truck with his 78-year-old mother as he struggled to remain conscious. "She never had asthma or COPD, now she's on inhalers full time."

Even months later, the town's residents reported mental fogginess, lung dysfunction, chronic fatigue and stomach disorders. They said they have trouble sleeping, afraid it could happen again.

investigation into the Satartia pipeline rupture, and the safety of CO2 pipelines. It is based on interviews with more than 60 witnesses, victims, first responders, lawyers, medical and toxicological experts, pipeline and petroleum experts, and public health officials; and a review of medical records, police and fire reports, 911 recordings, emergency dispatch logs, internal documents from the Mississippi Emergency Management Agency and the state Department of Environmental Quality, as well as federal pipeline incident reports.

Meanwhile, the federal government is taking the first steps to vastly increase the size of the nation's carbon dioxide pipeline network as a way of fighting climate change. Our investigation reveals that such pipelines pose threats that few are aware of and even fewer know how to handle.

"We got lucky," said Yazoo County Emergency Management Agency director Jack Willingham, who oversaw the rescue effort. "If the wind blew the other way, if it'd been later when people were sleeping, we would have had deaths."

A Deadly Gas

Carbon dioxide has long been used to euthanize laboratory rodents and other small animals, a practice animal welfare organizations now consider inhumane due to the suffering the gas inflicts on the animals. Each year, CO2 accidents kill about 100 workers worldwide — often in basements of restaurants that use CO2-charged systems for their bar mixers — or in industrial accidents.

Carbon dioxide is an asphyxiant that displaces ambient oxygen, making it more difficult to breathe. Smaller exposures cause coughing, dizziness and a panicky feeling called "air hunger." As CO2 concentrations get higher and exposure times longer, the gas causes a range of effects from unconsciousness to coma to

performance and inducing a confused, drunken-like state.

Denbury's entire business is built around piping carbon dioxide to oilfields and a few industrial users in two operational centers in the Gulf Coast and the Rockies. It owns or has an interest in 14 oil fields in Mississippi, Texas and Louisiana, which are connected by five CO2 pipelines spanning 925 miles. Among its properties is Tinsley Field, adjacent to Satartia, which became Mississippi's first commercially successful oil field in 1939.



Left: The Tinsley oil field in Tinsley, Mississippi, on July 23, 2021. Right: A CO2 gas pipeline remains active in Satartia, Mississippi, that same day.
Rory Doyle for HuffPost

In 2007, Denbury built its 31-mile Delta pipeline to connect Tinsley to the Jackson Dome, an extinct volcano under Jackson, Mississippi, whose 4.6 trillion cubic feet of naturally occurring CO2 gas supplies all of the company's fields. Denbury extended the Delta line 77 miles to Louisiana's Delhi field in 2009.

Denbury uses the CO2 for enhanced oil recovery, or EOR, which uses the gas to flush more oil out of wells. About 20% to 40% of the oil in a field can be recovered through conventional drilling and injecting water into the reservoir. Injecting CO2 after that can increase the yield up to 60%.

Tinsley itself suffered a sizeable CO2 "blowout" — where injected CO2 explodes out of the ground along with water, mud and drilling fluids — in 2011 that took 37 days to bring under control, sickened one worker, and killed deer, birds, fish and other animals.

Denbury had already had two other blowouts in Mississippi, one requiring the evacuation of local homes in Amite County in 2007. Another underground CO2 blowout at Delhi field in 2013 lasted for more than six weeks and contaminated the air with unsafe levels of both CO2 and methane.

Denbury and other companies that do EOR are well versed in the dangers of CO2. At Denbury's Heidelberg Field in eastern Mississippi, signs warn of a CO2 hazard and say SCBA must be worn, and there are muster stations where workers gather if there is a release. The company also has safety pamphlets on its website — one for the public called "Pipeline Safety Is Everybody's Responsibility" and another for first responders titled, "AWARE: Tactics for Responding to a CO2 Pipeline Leak." None of the emergency workers interviewed for this story had seen either.

While the risks of CO2 exposure were well established, the Satartia gassing was the first known instance of an outdoor mass exposure to piped CO2 gas anywhere in the world, according to Marcelo Korc, chief of the World Health Organization's Climate Change and Environmental Determinants of Health Unit, whose staff researched injuries from CO2 pipeline leaks in response to an inquiry from HuffPost.



The sun sets on the village of Satartia alongside the Yazoo River in July.
Rory Doyle for HuffPost

Korc's staff also found that CO2 from the Jackson Dome is contaminated with hydrogen sulfide, a deadly gas that likely worsened residents' symptoms and also accounts for the gas cloud's odor and greenish color, since pure CO2 is odorless and colorless.

Denbury declined to answer specific questions for this story, sending only a statement:

> *On February 22, 2020, at approximately 7:00 p.m., Denbury Enterprises' Delta pipeline experienced a sudden rupture and release of CO2 gas near Satartia, Mississippi. Before, during, and after the event, Denbury's main*

release and the surrounding environment. Denbury and its personnel were quickly in the community, working directly with nearby leadership and any individual residents affected by the event to ensure that any needs arising from the event were met. We have continued to work closely with the community and have made significant contributions to local emergency response organizations to support the important role they play in keeping the community safe. Denbury has cooperated fully with all federal, state, and local agencies who responded to the incident. The federal agency charged with regulating the pipeline continues its review and investigation of the incident, and Denbury continues to cooperate fully with their efforts.

Beyond the suffering of those who lived through it, the fact that the Biden administration is poised to commit unprecedented billions to carbon capture and sequestration (CCS) technology — putting CCS at the center of the country's strategy for reducing greenhouse gas emissions — further magnifies the importance of Satartia's CO2 accident.

The historic hike in federal support for CCS infrastructure includes taking the first steps toward the construction of a continent-spanning network of pipelines in order to move America's many millions of tons of CO2 to storage areas where, theoretically, the gas can be injected deep underground and sequestered indefinitely.

Some experts estimate this network will need to be as large as or even larger than the 2.6 million miles of existing petroleum pipelines. Meanwhile, there are only 5,000 miles of existing CO2 lines, meaning there is little experience with a wide range of operational — and safety — issues likely to arise from such a massive new system.

Nevertheless, Biden's climate team; his Department of Energy and three of its former secretaries; most utilities; the coal industry and the governments of several coal states; ExxonMobil, the rest of Big Oil and other major industrial corporations; several climate NGOs; the AFL-CIO; and a bipartisan group that

some form.

“We want to build more pipes,” DOE Secretary Jennifer Granholm told a reporter in June. “There’s a lot of jobs that are associated with decarbonizing … and I think pipes are one of those opportunities.”

But the rush to build and operate an integrated CCS and pipeline system has so far taken place with little examination of the safety issue, as the people of Satartia learned.

Korc of the WHO worried that the basic science done long ago on many toxic chemicals, including petroleum products, has never been done for CO2.

“The exposure studies simply don’t exist,” he said.

Satartia was, in effect, an unwitting case study for a monumental project.



Gas victim DeEmmeris Burns in July 2021, near the site where he was rescued in Satartia.
Rory Doyle for HuffPost

“They Can’t Come Evacuate Y’all”

DeEmmeris Burns was returning to his mother’s house in Satartia from a fishing trip with his brother Andrew Burns and cousin Victor Lewis when they heard an explosion and then a deafening roar, like a jet engine. The stench of rotten eggs filled the car.

DeEmmeris Burns immediately thought: pipeline explosion. He knew there was one nearby, but other than its approximate location, knew nothing else about it.

They were driving on Perry Creek Road, a gravel and dirt country lane that hugs its namesake waterway and passes close to but below the location of the pipe rupture. They were almost at his mother’s house.

explosion.

“You got to get out. We’re close, we’re coming to get you,” Burns shouted over the roar of escaping gas.

On the other end of the call, 65-year-old Thelma Brown was trying to figure out why her son sounded so strange. He was hollering, breathing heavily, not making sense. She knew the pipeline he was talking about; it runs about half a mile from her house. But she hadn’t smelled anything. She heard her son frantically repeating, “Cut the air! Cut everything off! Cut the air!” And then, silence.

She tried calling him back. No answer. She rang the other two men’s cell phones, but got nothing.

Inside the car, the three men rolled up the windows to keep out whatever it was they were driving through. Then the engine died.

“Hunh,” Burns said. “Car shut off.”

Minutes later, Thelma’s sister, Linda Garrett, who lived just down the road, smelled the gas and called too. Thelma repeated what her sons had told her before their call dropped.

Garrett hung up with Thelma and called 911, but the dispatcher didn’t seem to know about a gas leak.

“Do I need to be getting out of here?” Garrett asked. The 911 operator said she’d call her back and let her know.

“She can’t breathe. She’s on the floor right now”

0:00 / 3:43

Garrett noticed her own breathing was becoming labored. Then her daughter Lynett Garrett and 14-year-old granddaughter, Makaylan Burns, who had been out picking up a pizza for dinner, staggered in the door.

Makaylan seemed to be in full-blown respiratory distress, and Lynett was unable to talk. She pounded on the dining room table and panted.

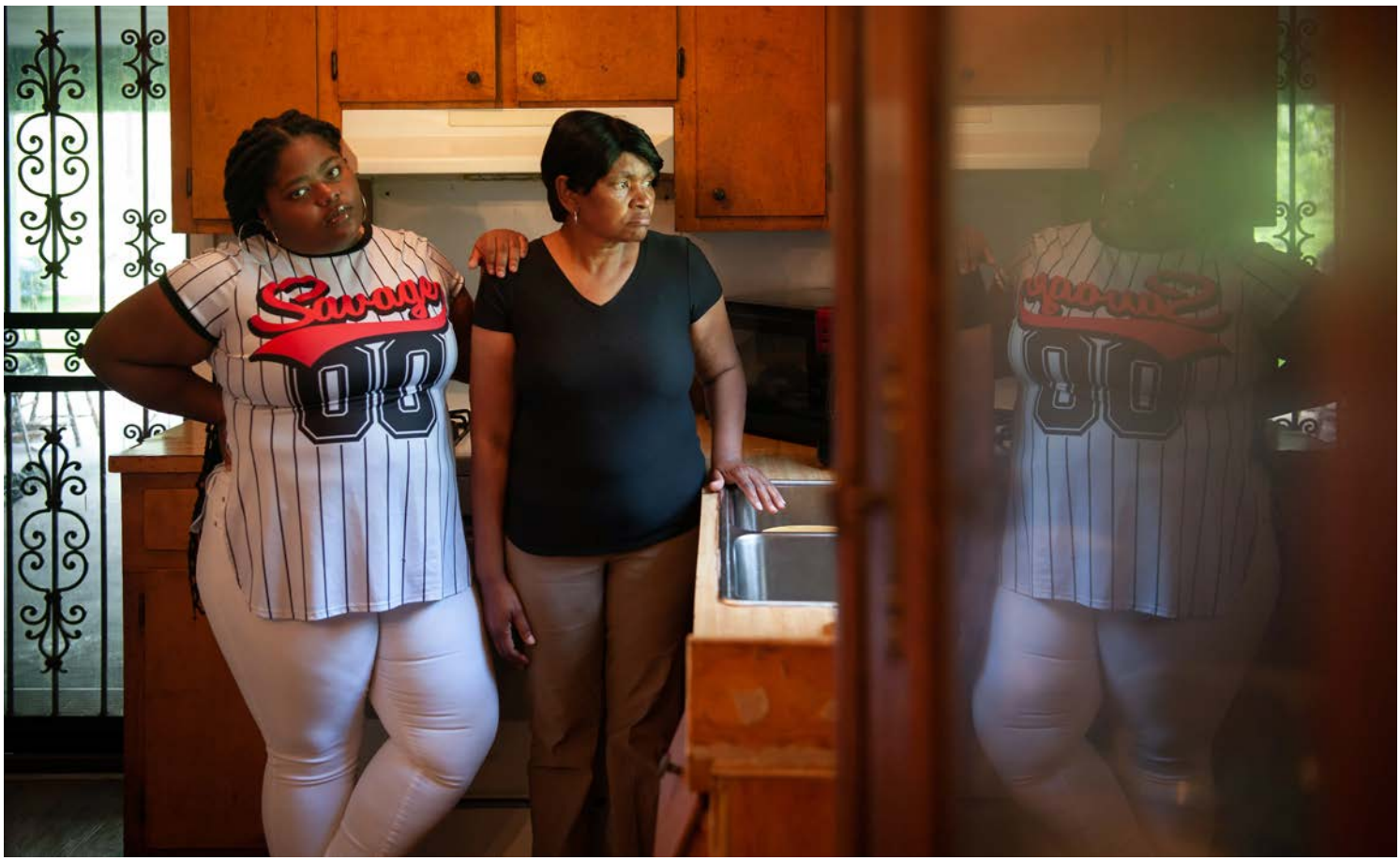
“What is it? What’s wrong? What is it?” Garrett shouted.

Makaylan dropped to the floor, unconscious.

Garrett tried 911 again. This time the operator acknowledged that there was a gas leak.

“They have shut the highway down because of it. They’re not letting anyone in, they can’t come evacuate y’all,” she said.

Garrett was afraid if they left the house, all three of them would pass out. She insisted on an ambulance. The dispatcher said one would meet them outside of town.



Gas victims Linda Garrett (right) and her granddaughter, Makaylan Burns, in Garrett's kitchen in Satartia in July.
Rory Doyle for HuffPost

Garrett and Lynett carried Makaylan out to the car. Garrett had a bad back and both adults were having trouble breathing, but they managed to get the teenager into the back seat, still unconscious.

Lynett drove and Garrett stayed on the phone with 911 as the operator told them the best route out of town. But after a few minutes, Garrett's breath "just cut out." "We ain't going to make it,'' she said, before she blacked out. Lynett drove to where they were supposed to meet the ambulance, but it didn't show up, and she had to drive to the hospital.

Back at her house, Thelma Brown ran outside to round up her 8- and 3-year-old grandchildren. She brought them into her bedroom, along with her 2-month-old grandson. The oldest, who has asthma but hadn't suffered an attack for some

gave some to the 3-year-old too, since she had been outside. Brown closed the windows and blocked air from coming in under the door with a wet towel.

Other relatives called, urging her to get out. But her pickup had a flat, and she was alone with three children. Her daughter was supposed to come get the kids after work, but called and told Brown that all the roads into the area were blocked off. Garrett told Brown what 911 had told her: that emergency workers were not coming into town to evacuate victims.

“I talked to the Lord. I said, ‘Lord, me and these kids going to bed,’” recalled Brown. “And I said, ‘We’re going to stay here until somebody comes and gets us out of here.’”

She waited for her son and the others to show up. She fell asleep.



Rory Doyle for HuffPost

At the same time, a group of friends were cooking crayfish and sipping beer at a fishing camp along the Yazoo River. It was getting dark when Hugh Martin noticed the rotten egg smell. Soon they were all wheezing and breathing hard. Martin's friend, Casey Sanders, collapsed onto the ground, then quickly came to.

Coughing and choking, everyone somehow made it to their vehicles. Martin jumped into his white pickup truck and drove up onto the levee that separates the town from the river. The glare of his headlights illuminated a green, misty fog. The suffocating feeling was nearly intolerable. "Only thing I been through worse than this was the gas chamber when I was in the Army training for Desert Storm," he said. "And that was CS gas." CS gas is a type of tear gas.

He called his elderly mother, Marguerite Vinson, who told him she was feeling dizzy.

"Got your shoes on, mama?" he asked, trying to keep the anxiety out of his voice. He told her to meet him in the carport of their home, not far from the fishing camp. After stopping once to throw up out of the truck window, he made it home.

"I saw mama standing there, holding her phone, and she was weak at the knees. And I just grabbed her and throwed her in the truck," said Martin. "Then I just took off and headed for the highway."

At the stop sign at Route 3 was a checkpoint, but he blew by it, heading north to the hospital in Yazoo City. His mother lay motionless on the passenger's seat: Her eyes were open, but she stared blankly ahead when he spoke to her.

At the hospital, he found others from the crayfish cook, including Casey Sanders, and learned that her teenage son, Nathan Weston Sanders, and his girlfriend were missing, after leaving the fishing camp minutes before the explosion.

Sanders had collapsed. She couldn't revive him and didn't know where they were. Now, Sanders' father and another man from the crayfish gathering were driving back into the fog to look for them.

An Improvised Response

Sheriff's Officer Terry Gann was at a grocery store, taking a break from a long day working a double homicide when he received an EMS alert about a motorist who had a seizure due to a "green fog" crossing Route 433 east of the town.

"My friend, she's laying on the ground, she's shaking, she's drooling out of the mouth"

0:00 / 2:51

Yazoo is Mississippi's biggest county at 923 square miles, but it's an economically disadvantaged one, with just 11 sheriff's officers who get called in for everything from tornadoes and floods to industrial accidents. Even though he is the county's only criminal investigator, Gann works the disasters too. At 7:32 p.m., he headed toward Satartia in his truck.

EMS advised responders that self-contained breathing apparatus was required to enter the "hot zone" inside the roadblocks, where the gas had settled. Gann didn't have SCBA with him, but he went in anyway.

had gone missing in the gas plume, not far from the ruptured pipe. The cloud was moving slowly northwest, so first Gann took the road over the levee to enter the village from the south to evacuate any remaining residents.



Terry Gann, chief investigator for the Yazoo County Sheriff's Department, with the truck he used to rescue gas victims in Satartia.
Rory Doyle for HuffPost

He did a round of checks on houses, banging on doors and peering through windows, but found no one. Around him he saw — and felt — the cloud. “It’s like I just ran a mile as fast as I could. My ears were popping. My face was burning like a sunburn.”

River, out of the cloud, to catch his breath and get the vehicle running, then returned to check more houses. Just outside of town, he found a young man and woman pacing the middle of an intersection.

“It was almost like something you’d see in a zombie movie. They were just walking in circles,” he said. “I kept telling ’em, ‘Y’all get in the truck.’ And they would just look at me with this blank look on their face. And the girl was holding a phone up to her head but she wasn’t saying nothing. … Finally I just yelled at ’em, I said, ‘Get in the truck or you’re gonna die!’”

Gann shoved the dazed teenagers into the back seat, not knowing it was Nathan Weston Sanders and his girlfriend.

After picking up a woman he found unresponsive in a stalled car, his engine began sputtering again, so he returned to the command post to meet the ambulance. By the time they got there, Gann himself could barely breathe and had to be given oxygen.

He did one last search of Satartia, then messaged dispatch, “Everyone evacuated” at 9 p.m. He radioed that he was heading for Perry Creek Road, which hadn’t yet been searched.

That worried Jack Willingham, director of Yazoo County Emergency Management Agency, since Gann had been breathing high levels of CO2 for nearly two hours and was panting audibly over the radio. His speech was often slurred and when it wasn’t, it didn’t always make sense. Willingham ordered Gann to leave the “hot zone” immediately and get medical attention.

But Gann, disoriented by the lack of oxygen, got lost and never made it to Perry Creek. With radio guidance, he met an ambulance that took him to a hospital in Yazoo City. After two hours of oxygen treatments, he went home, utterly spent.

'em, I said, 'Get in the truck or you're gonna die!'

By then, however, a three-man team of Vicksburg firefighters was on its way to Perry Creek Road.

They were driving a UTV, or utility task vehicle, a small ATV-like two-seater with an open cargo bed in back that held spare air bottles and tools. Jerry Briggs, fire coordinator for Warren County, squatted in the cargo area with Warren County 911 director Shane Garrard, while Lamar Frederick, a Vicksburg fire chief, drove. Each wore 60 pounds of fire protective clothing and gear, including SCBA.

After making their own fruitless search of the village, they decided that rather than return empty handed, they would enter the blast area via Perry Creek Road. The roar of the ruptured pipeline was deafening as they approached.

A half mile up Perry Creek Road, they saw a car with its lights on and windows up just as the UTV began stalling.

"We got victims," Frederick yelled above the roar.

Inside the small red Cadillac sedan were three men: DeEmmeris and Andrew Burns, and Victor Lewis. DeEmmeris Burns lay across the backseat in the fetal position. The other two were slumped against the windows, white foam coming out of their noses and mouths, their clothes stained with urine and excrement. The firemen thought they were too late.

The doors were stuck, so Briggs smashed the right rear window. The three were still breathing, though just barely. The rescuers shook them and tried sternum rubs, but got no reaction.



Warren County firefighter Jerry Briggs in July with the utility task vehicle he used during the February 2020 gas leak in Satartia.
Rory Doyle for HuffPost

Panting in exhaustion and sweating under all their gear, they managed to get all three out and cram them into the UTV.

They headed toward the south command post. After a few minutes of fresh air, the victims began to stir. Then they tried to stand up. They seemed about to fall off when a truck full of county deputies met up with the UTV, and one of the deputies bear-hugged the men into place until they met the ambulance.

The firemen had just a few minutes to breath fresh air and chug water before Willingham sent them to evacuate a group of mostly elderly residents just across the river. Willingham and the National Weather Service office in Jackson were tracking the plume as it headed northwest, and Willingham was determined to get ahead of it.

monitoring contractor, the Center for Toxicology and Environmental Health; the environmental remediation firm E3; an investigator for the federal Pipeline Hazardous Materials Safety Administration (PHMSA); and officials from the Mississippi's Emergency Management Agency and Department of Environmental Quality.

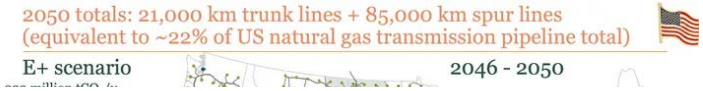
At 11:06 p.m., the Denbury team "observed no product coming from the failure location," according Denbury's report to PHMSA. The leak was officially declared over.

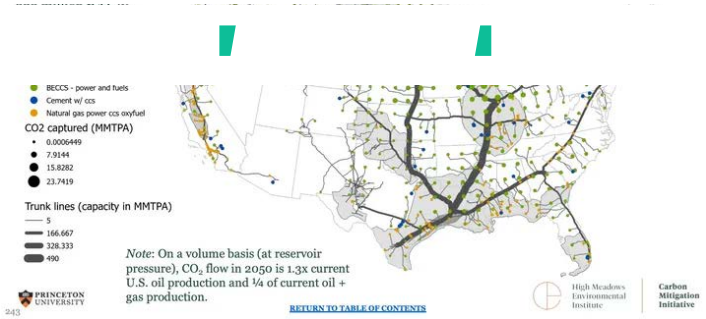
A Massive Buildout

Once the province of a few policy wonks and coal companies, shipping carbon dioxide and storing it underground has gotten much more mainstream attention in recent years amid a tsunami of conferences, draft legislation and interest groups.

The fossil fuel industry has gotten behind CCS as a technology that, it hopes, would allow continued production so long as the emissions are buried underground. But the immense network of pipelines needed to transport carbon dioxide to locations where it would be stored deep below ground weren't discussed publicly until recently, nor was how such a rapid, unprecedented pipeline buildout could be done.

A much-touted December 2020 Princeton University study — funded in part by the oil industry — calls for a 65,000-mile system by 2050, which means adding 60,000 miles to the current 5,000 miles of CO2 pipeline. The new system would be organized into a spider web of continent-spanning trunk lines as large as 4′ in diameter — twice the size of the Satartia pipeline — fed by a system of smaller spur lines.





Princeton Net-Zero America Report

But even 65,000 miles of pipeline could only move 15% of current U.S. greenhouse gas emissions. To have any effect on climate change "would entail CO2 pipeline capacity larger than the existing petroleum pipeline system," which totals 2.6 million miles, according to a 2020 study in Biophysical Economics and Sustainability.

Beginning with the Bush administration, the U.S. government has spent over $8 billion to promote carbon capture and storage (CCS). But almost all of the CO2 in current pipelines is used for enhanced oil recovery rather than being injected deep into the earth for secure geologic storage, and enhanced oil recovery produces more emissions than it sequesters. Almost none of today's CO2 is manmade, but comes from natural sources like the Jackson Dome.

Proposals like Princeton's would likely require extending CO2 pipelines into heavily populated areas, across mountains and other natural barriers. The cost of such an enormous system is driving some to suggest simply repurposing existing natural gas pipelines to move CO2.

But because CO2 is corrosive and will eat through the carbon steel used in petroleum pipelines if contaminated with even small amounts of water, CO2 pipelines have to be manufactured to a higher standard and the purity of the gas carefully monitored. And research shows that CO2 from a commonly used carbon capture technique is particularly likely to have water in it. CO2 pipelines also run at significantly higher pressures than natural gas pipelines, which in turn requires more energy-gobbling compressor stations along the line to keep the CO2 in a liquid state.

existing natural gas pipelines to move CO2. The American Petroleum Institute has also highlighted the risks.

Yet an influential white paper produced jointly by the Energy Futures Initiative, headed by former U.S. Energy Secretary Ernest Moniz, and the AFL-CIO proposes doing just that. “Repurposing the expansive U.S. network of existing oil and gas pipelines presents a ripe opportunity to lower costs for CO2 transport,” said the report.

Moniz was Biden’s energy adviser in his 2020 presidential campaign, and oversaw billions in spending on CCS in his time at the Department of Energy. He and his team are considered leading experts on both natural gas and carbon dioxide infrastructure. Yet the petroleum industry’s own longstanding warnings about mixing gas technology with carbon dioxide are nowhere to be found in a 79-page report or its 299 footnotes.

“So much of it is about cost cutting, finding ways to do things cheaper and where can you make compromises,” said Carroll Muffett, president of the Center for International Environmental Law and co-author of a highly critical report on CCS and pipelines.

Muffett noted that CO2 behaves differently from natural gas inside a pipeline — in ways that make a CO2 rupture uniquely dangerous.

“Because of the intense pressures involved, explosive decompression of a CO2 pipeline releases more gas, more quickly, than an equivalent explosion in a gas pipeline,” noted a report by CIEL and the Environmental Working Group, and “even a modest rupture can spread freezing CO2 over a wide area within seconds.”

A complicating factor in the Satartia accident was the presence of hydrogen sulfide. A Mississippi Emergency Management Agency email from the night of the accident said the leak contained an “unknown amount of pressurized CO2 with H2S.” CO2 is often contaminated with hydrogen sulfide, and Muffett points

health effects that can include damage to the nervous system, lungs, liver and heart.

Even CO2 by itself, however, can be quite lethal. On a summer day in 1986, a thick plume of CO2 from a volcanic lake in Cameroon killed 1,746 people. Birds dropped out of the sky and whole families died together in minutes.

Short of death, however, there is a wide range of CO2 inhalation effects, which include dizziness, headache, nausea, shortness of breath, increased heart rate, memory disturbances, lack of concentration, disorientation, convulsions, and unconsciousness — symptoms that closely track those of Satartia's gassing victims.

Unfortunately, few emergency rooms are familiar with the range of its effects.

A Scramble At The Hospital

When DeEmmeris Burns woke up, he was sitting in a chair near a nurse's station. He had no idea how he got to the hospital.

An IV was running down his arm, and his brother and cousin were in adjoining chairs. His lungs burned and his head ached. He was still in his soiled clothes.

"They didn't put us in rooms. I mean, it was just all bad," he remembered. "The nurses weren't prepared for this."

The hospitals told HuffPost that they responded appropriately under standard protocols for a mass toxic incident, but would not comment on specific cases.

At around 12:30 a.m., Sarah Belk, who had grown up with the Burns brothers, found the three sitting in chairs, wrapped in a single blanket. Belk had brought her own mother and daughter to the ER after they escaped from Sataria.

> ***realizing the extent of what was going on with these people," she said.***
>
> *Sarah Belk*

Andrew Burns asked where they were, and she told them they were at the hospital in Vicksburg, that their car stalled in the cloud of gas, and they'd been found unconscious. They were shivering "like they were in shock," Belk said.

She saw their stained clothes and the dried foam on their faces. All three were thirsty. No one was attending to them, and the nurses seemed dismissive and rude, Belk said.

"I felt that they were not realizing the extent of what was going on with these people," she said.

Belk's 16-year-old daughter, Ellie, had thrown up, and was still red-faced from the lack of air during her escape from Satartia. Belk's 57-year-old mother, who has COPD, was also struggling to breathe, and after more than an hour of gas exposure, her complexion "was gray." But Belk said she still struggled to get them oxygen or basic attention. The hospital seemed overwhelmed.

Belk let the three men borrow her phone to call their families.

"I'm like, 'What's going on?'" Berneva Lewis, Victor Lewis' mother, remembered. "'We're at the hospital.' That's all they could tell me on the phone. I'm like, 'What happened?' They're like, 'They said we were in gas.'"

Given how disoriented they were, Lewis was startled to get a call at 2 a.m. saying the men were being released. "It was ridiculous. They were out before I could even get to the hospital," she said.

father's home in Vicksburg. They were still in the same clothes they'd worn upon arrival.

Of some 49 gassing victims who went to the hospital, almost all were treated at Merit Health River Region in Vicksburg or Baptist Memorial Hospital in Yazoo City. But the victims say neither facility seemed prepared for how to deal with this kind of disaster. In response to questions from HuffPost, both hospitals acknowledged they based treatment on standard toxic event protocols, which included setting up unheated outdoor decontamination tents to undress and wash victims — despite temperatures in the low 40s that day.

Neither hospital said they'd received any special training in handling a CO2 pipeline incident. Medical records for four gassing victims treated at Baptist Memorial — and for six of those from Merit River Region, including the Burns brothers and Lewis — seem to reflect confusion about what they were exposed to.

"Asphyxiation by environmental toxic gas, accidental or unintentional initial encounter. CO2, H2S, chlorine gas exposure from ruptured gas line," reads the report for all four of the Baptist patients. Later the records cite "natural gas exposure."

"They [were] nowhere near ready for something like that to happen," Hugh Martin said. "They were understaffed, but they also didn't know what the hell they were dealing with."

For Denbury, An "Incident" Without Consequences

Denbury knew about the accident before anyone. At 7:07 p.m., a low pressure alarm at its Texas headquarters alerted the company that the pipeline was leaking, and the company closed the main operating valves for the Satartia section of the line at 7:15 p.m., according to Denbury's incident report to the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).

responders, but both Fire Chief Durward Pettis and county Emergency Management Director Jack Willingham said nobody called them.

Denbury had no contact with them until Pettis called the company at about 7:45 p.m., according to the Yazoo County emergency dispatch log, and even then provided no guidance on the response or how to treat CO2 inhalation victims.

Without that guidance, 911 operators told callers there had been a natural gas pipeline rupture. But natural gas and CO2 are quite different. Natural gas is lighter than air, travels straight up, and is highly flammable. Exposure to CO2 mixed with hydrogen sulfide, on the other hand, can cause death from asphyxiation as well as lung damage. Residents of Sartaria were given no information about how to respond to such a mixture.

In the weeks that followed, Denbury also appears not to have disclosed the extent of the pipeline breach to investors.

“The affected pipeline segment was [isolated] within minutes of detection,” Denbury’s Senior Vice President of Operations David Sheppard said during a Feb. 25 quarterly earnings call. “And as a precaution, the area surrounding the leak site was evacuated, including residents of the small nearby town of Satartia. No injuries to local residents, our employees, our contractors were reported in association with the leak.”



LEFT: The CO2 pipeline rupture. RIGHT: Vehicles pass over the pipeline explosion site in Satartia in July.
Yazoo County Emergency Management Agency/Rory Doyle for HuffPost

To date, that is Denbury's most detailed public statement on the CO2 pipeline leak. Its filings with the Securities and Exchange Commission make no mention of a pipeline accident or leak, the evacuation, the injuries to residents, or any other details. Its 2021 annual report made two oblique references to the explosion, noting an oil production decline in 2020 at its Delhi, Louisiana, oil field "due to the lack of CO2 purchases between late-February and late-October 2020 as a result of the Delta-Tinsley CO2 pipeline being down for repair during that period" and "$4.3 million of costs associated with the Delta-Tinsley CO2 pipeline repair."

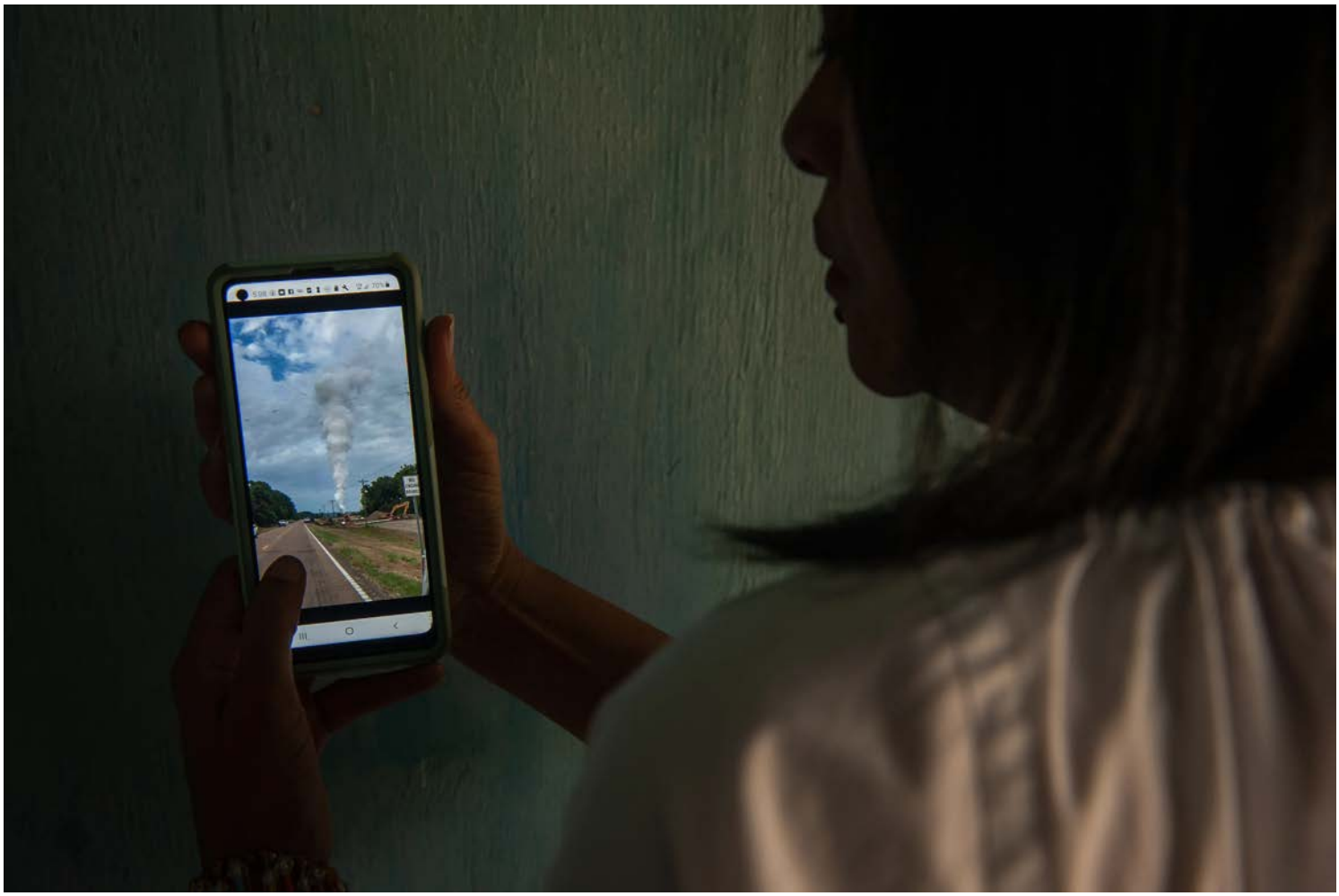
Denbury did disclose a total of 46 hospitalizations and 200 evacuees — the latter a little lower than the number reported by other sources — in its incident report to PHMSA.

Denbury also did not disclose that on Oct. 7, 2020, there was another accident while reconnecting the damaged pipeline section. While workers did a "controlled blow-down" to remove any remaining CO2 from the section, a valve "froze in the open position due to internal ice formation" and gas poured out, according to Denbury's report to the state Department of Environmental Quality. Multiple attempts to close it failed, and some residents had to be evacuated that night on short notice. But the second incident lasted longer — almost an entire

22 incident lasted four hours and released 31,407 barrels.

Why the pipeline initially ruptured also has yet to be determined. A PHMSA spokesman declined to comment on when its official report on the incident might be released.

Meanwhile, Denbury sent a section of the pipeline to a metallurgical lab for testing. Based on those findings and its contention that the pipeline was “code compliant,” it theorized in its report to PHMSA that soil movement caused by persistent heavy rains “induced axial stresses” that caused a rupture.



Berneva Lewis plays a video of an October 2020 gas leak in Satartia.
Rory Doyle for HuffPost.

evacuations along the Yazoo and Mississippi rivers. But Chad Jones, a plaintiff's lawyer representing gassing victims who is also a geologist, said flooding is common in the Delta, and should have been anticipated when the pipeline was built in 2007. Jones noted several other factors that should have been taken into account during construction as well: the soil in the area, called loess, is unstable and prone to shifting and mudslides, and building a pipeline through such soil requires special techniques because any rupture in that area would send the gas downhill into Satartia.

"They might claim an act of God," said Jones, "but I mean, we can prove that it wasn't."

Denbury Resources filed for bankruptcy five months after the incident, citing the pandemic crash in oil prices. It emerged from Chapter 11 in September 2020 after shedding $2.1 billion in debt and its old name. In March 2021, the newly restructured Denbury Inc. gave a presentation at the 26th Annual Credit Suisse Energy Summit recounting highlights of 2020, including "record levels of safety performance for the fourth consecutive year."

Among the new capital investments for 2021 that Denbury CEO Chris Kendall and other officials unveiled was a $7 million plan boosting CO2-based drilling operations in the Tinsley field — using the same pipeline that ruptured in 2020.

The Next Day

Officer Terry Gann got three hours of sleep before heading back to Satartia.

Abandoned vehicles were everywhere — doors ajar, many with their windows smashed from the rescue efforts. Gann had the keys to several, and rescuers set up a kind of lost and found on the side of the road.

Gann helped Denbury personnel, including technicians with gas measuring equipment, escort villagers back to their homes. The rotten egg odor was still heavy in the air.

technician's gas meter hit the red zone, and they had to leave until levels went down.

That evening, Satartia Mayor Kathy Nesbit, Pettis and several Denbury representatives presided over a standing-room-only meeting at First Baptist Church. Bruce Augustine, Denbury's operations manager, told the crowd that the company was "very happy that the air monitoring we've done shows that everyone can now return to their homes."

Denbury officials said they would be stationed at the town hall to deal with any problems or complaints, and that residents would be promptly reimbursed for medical bills. While there was some discussion of safety measures to prevent a repeat disaster, nothing definite was promised.

Nesbit, an intensive care nurse who had been working at River Region hospital the night before, tried to dispel fears of long-term health effects. "It is a natural chemical in our bodies," she said. "So it's not a poison that's going to infiltrate you and eventually kill you."

That was cold comfort to many survivors, some of whom noted pointedly that Nesbit hadn't been in town that night and didn't experience being inside the plume.

When it was over, Thelma Brown and Berneva Lewis thanked Vicksburg firefighters Jerry Briggs and Shane Garrard for saving their sons. "That was when they actually told us about the condition that the guys were in and how they were very near death and foaming at the mouth," Brown said.



Warren County firefighters Shane Garrard (left) and Lamar Frederick in Vicksburg, Mississippi, in July. They're next to the utility task vehicle they used during the February 2020 gas leak in Satartia.
Rory Doyle for HuffPost.

DeEmmeris and Andrew Burns and Victor Lewis were still in no shape to go to any meetings. After a sleepless night, more vomiting and severe headaches, they spent early Sunday on oxygen, being monitored and having bloodwork done at the University of Mississippi Medical Center in Jackson, the state's flagship teaching hospital. Even after that, Lewis told his mother, who is a nurse, that he still felt terrible.

She took all three to another doctor the next day, and tests revealed that their blood CO2 levels were still alarmingly high. The doctor said they would need to remain on oxygen until the numbers came down, and sent them to a pulmonologist.

medical bills quickly. Residents were asked to drop by Town Hall to discuss compensation for other losses, like pain and suffering. Those who accepted were paid on the spot, but waived their right to sue or discuss the settlement.

But many victims, some of whom say they are still sick, anxious and unable to fully return to their previous lives, weren't interested in a deal and decided to sue. The Burns brothers and Lewis hired Robert Gibbs, a well known lawyer from Jackson. Their suit will claim Denbury failed to properly maintain the pipeline or take necessary safety precautions to prevent exposure to hazardous gas, Gibbs said.

Another who decided to sue was Martin, whose occasional breathing difficulties from mild COPD have required much more frequent use of his inhaler since the February 2020 incident.

Medical records also show that months after the incident, his 78-year-old mother, who had no previous history of breathing difficulties, was using albuterol constantly, getting oxygen treatments, and had to be hospitalized for a week in March 2020 after he found her lying unresponsive in bed and having trouble breathing.

Marguerite Vinson was frustrated that not only was she not recovering, she seemed to be getting sicker.

"I can't think half-right! And I just wear out. Anything I try to do, it's hard to do if it requires exertion," she said.

Linda Garrett said Denbury asked to meet with her three weeks after the incident and offered her a package deal — $5,000 each for her, her daughter and granddaughter, which she refused. She said she heard one neighbor, who is white, had been offered $10,000, and that another white neighbor had been given $18,000 compensation for cows that miscarried after the incident.

"They value a cow more than they do a human," Garrett said.

Not long after the gassing, DeEmmeris Burns' phone rang. According to Burns, the voice on the other end identified himself as Denbury CEO Chris Kendall.

"He asked me 'How's everything going?'" said Burns. "I just told him I've got someone talking for me now."

"You Should've Told Us."

Over a year and a half after the gassing incident, the Burns brothers and Lewis still have not returned to work. They were under a doctor's care until February 2021, when they were taken off oxygen, said Gibbs. DeEmmeris Burns moved out of his mother's house because, he said, it's too painful for him to drive up Perry Creek Road.

Gibbs said his and some nine other law firms representing the Satartia CO2 plaintiffs have joined forces as the Denbury Litigation Group. While Gibbs represents only the three Perry Creek Road victims, some lawyers have as many as 60 or 70 clients. None has yet filed suit, awaiting the long-delayed Pipeline and Hazardous Materials Safety Administration report on the reasons for the accident.

Martin said he hopes a lawsuit will pry out all the facts about what happened that night and why.

"If there's this many malfunctions in that one section of pipeline, somebody was at fault, or they were passing inspections they shouldn't have passed," said Martin. "That's what we need to find out."

Nevertheless, opinions differ as to how or even whether Denbury should be held accountable. One reason may be an inherent reluctance to criticize the oil and gas industry, a source of scarce well-paid jobs as well as a statewide political power. Some are willing to consider the pipeline rupture "an act of God," though

of the disaster.



The sun sets on the village of Satartia alongside the Yazoo River in July.
Rory Doyle for HuffPost

Interestingly, only a few of the residents interviewed for this article had heard of carbon capture and sequestration — and none knew about plans for a greatly expanded CO2 pipeline network.

“That doesn’t make any sense,” said Martin. “Not when they can’t control what they’ve already got. I think there’s real basic questions that need to be answered

Linda Garrett said she still struggles with back pain from carrying Makaylan to the car that day. Makaylan's asthma, which had been in remission, is worse than ever, and both her daughter and granddaughter remain traumatized. She wants the company punished.

Denbury, she said, should have warned the town before there was an emergency.

"If you cared about us, you and the pipeline, you should have let us know," Garrett said. "But you didn't let us know nothing. You just telling us now. That doesn't seem right to me. Sometimes we have to be held accountable for the things that happen."

CORRECTIONS: *An earlier version of this article misidentified a person affected as Lynett Burns. The woman's name is Lynett Garrett. An earlier version of this article also misquoted Hugh Martin as saying his Army training for Desert Storm included "cyanide gas," rather than "CS gas."*

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