Via Email
October 16, 2024

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

Dear Chairman Couch and Honorable Supervisors:

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 Final Recirculated Environmental Impact Report (the Final REIR or the REIR) 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 Dominic DiGiulio, PhD (Attachment A); and Richard Kuprewicz (Attachment B). We refer the County to these reports, both here and throughout these comments, for further discussion of the Final REIR's inadequacies.

These comments follow previous comments we submitted on March 1, 2024, June 21, 2024, and July 18, 2024 in response to the original December 19, 2023 Draft EIR and the June 4, 2024 Recirculated Draft EIR for the CTV I Project.[3] The Final REIR fails to remedy the legal deficiencies identified in the Draft and Recirculated EIRs. Indeed, in many instances, the Final REIR fails to respond substantively—or does not respond at all—to the concerns we raised in

[1] Pub. Resources Code, § 21000 *et seq*.
[2] Cal. Code Regs., tit. 14, § 15000 *et seq*. (CEQA Guidelines).
[3] We refer to our comments on the December 19, 2023 Draft EIR as "DEIR Comments" and on the June 4, 2024 Recirculated Draft EIR as "RDEIR Comments."

our previous comments. The Final REIR is therefore inadequate under CEQA. This letter supplements and expands upon the arguments in our prior letters, but it is not intended to be exhaustive and incorporates by reference arguments made previously.

We also continue to urge the County to conduct a genuinely inclusive public process for the CTV I Project. The County is advancing this Project, Aera's CarbonFrontier CCS project, and the County's Carbon Management Business Park—all major CCS-related proposals that are the first of their kind in California—on similar timelines.[4] Meanwhile, the County is expecting the public to review thousands of pages of highly technical reports and appendices for these projects simultaneously. This approach creates unnecessary burdens for the public to participate in the County's decision-making process for multiple controversial projects that pose long-term threats to community members' health and safety. Given the significance of these projects to Kern County and the entire state, the County should instead be engaging in a transparent and deliberate process that allows for concerned citizens to fully assess and comment upon the CEQA documentation.

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

[4] See Dept. of Energy, *Kern County Finds Economic Opportunities Beyond Oil and Gas Production in a "Carbon Management Business Park"* (July 17, 2024), https://www.energy.gov/communitiesLEAP/articles/kern-county-finds-economic-opportunities-beyond-oil-and-gas-production (The County discussing the Carbon Management Business Park and stating "we have three companies, two in the valley area of Kern County near proposed CCS areas and one in the desert area of Kern County near rail that are working with consultants on plans to submit for areas up to 9,000 acres each. They all have indicated they have companies interested in locating in such a park.").

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I. THE FINAL REIR'S ANALYSIS AND MITIGATION ARE BASED ON AN IMPROPER PROJECT DESCRIPTION

The Final REIR's project description is inadequate under CEQA because it still fails to 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."[5]

The Final REIR still fails to include the whole of the action in its analysis, and to analyze reasonably foreseeable and significant consequences of the CTV I Project, because it fails to address critical components of the Project, including its effect on the development of industries in Kern County that will send CO_2 for sequestration, the effect of the Project on the development of CO_2 transportation infrastructure, and the resulting environmental impacts. The narrow and vague description of the Project and its scope also renders the Final REIR informationally inadequate.

A. The Project Description Should Have Included and Accounted for CO_2-sending Sources.

The Final REIR goes to great lengths to explain why the Project stands on its own, but it should be clear from the outset – the CO_2-sending sources are an inseparable part of a carbon capture and sequestration project and cannot be viewed in separation. The CO_2 pipelines, the compression and injection infrastructure, the injection and monitoring wells, the pore space, and the monitoring devices all exist to receive and store CO_2 and have no independent utility.

There is no dispute that the Final REIR seeks to approve a 9,104-acre CCS facility with related capture facilities and pipelines for the initial source.[6] There is no dispute that the Project's CO_2 storage capacity will be 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 Final REIR.[7] There is also no dispute that the only CO_2 source analyzed in the Final REIR is the pre-combustion Elk Hills oil field gas, which, as the Final REIR concedes, will at most provide about 4 million tons total of CO_2 for injection over the next 20 years, or about *10% of the storage capacity the Final REIR is seeking to approve*.[8] The County added to the Recirculated Draft EIR a new short section titled "Future Sources – Identification"[9] where it very briefly describes companies that "have announced contractual relationships or interest in locating on" properties outside the Project area or in "sending CO_2 for injection at CTV I."[10] Some of these future

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[5] *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).
[6] RDEIR, Vol. 1 at 3-1.
[7] RDEIR, Vol. 1 at 4.8-19.
[8] The Final REIR's analysis discloses that at maximum, the initial source's CO_2 will add up to 203,485 tons per year (tpy) of captured CO_2. RDEIR, Vol. 1 at 3-2.
[9] RDEIR, Vol. 1 at 3-13 to 3-15.
[10] RDEIR, Vol. 1 at 3-14.

sources have entered into a Carbon Dioxide Management Agreement (CDMA) with the Project applicant California Resources Corporation (CRC).[11]

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, oil field gas streams, power plants, direct air capture (DAC), and alternative fuel production.[12]

The Final REIR 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."[13]

However, no further analysis is conducted. Information regarding the potential CO_2 sources and the Project's cumulative projects is still inadequate, in violation of CEQA's mandate to analyze "the whole of an action that has the potential to cause direct or indirect physical changes to the environment."[14] The Final REIR does not correct any of the flaws previously identified in the project description.

In its Response to Comments, the County concedes that projects included in the cumulative projects list (which, in general, includes the CO_2 sources listed in the "Future Sources - Identification" sections) are reasonably foreseeable: "Because some potential future CO_2 source projects are reasonably foreseeable, they are included in the RDEIR's cumulative impact analysis."[15]

But the County argues that under *Banning Ranch*, "even reasonably foreseeable future projects need not be included in the same EIR if the proposed project has independent utility whether or not the other projects proceed."[16] The County admits that the Project includes the full capacity of the 26R and A1/A2 reservoirs, and that the reservoirs "provide large-scale opportunity for storage that would be wasted if additional CO_2 sources never come online,"[17] but argues that based on an economic report (WZI Report) the "project has independent utility because it is economically feasible without them."[18]

The WZI Report concludes that the proposed Project, "which consists solely of capturing Elk Hills' CO_2 and injecting it in the existing Elk Hills pore space, would be viewed as a stand-

[11] RDEIR, Vol. 1 at 3-15.
[12] RDEIR, Vol. 1 at 3-13.
[13] RDEIR, Vol. 1 at 3-45 to 3-47.
[14] CEQA Guidelines, § 15378(a); see *Habitat Watershed Caretakers v. City of Santa Cruz* (2013) Cal.App.4th 1277, 1297.
[15] Final REIR, Vol. 3, Response GR-1a at 7-16.
[16] Final REIR, Vol. 3, Response GR-1a at 7-16.
[17] Final REIR, Vol. 3, Response GR-1a at 7-17.
[18] Final REIR, Vol. 3, Response GR-1a at 7-17.

alone project worth pursuing with little economic risk independent of whether or not additional CO_2 sources are developed."[19] The Report finds that the Project's returns exceed the costs by year four of operation.[20]

The County further argues that implementation of the projects identified as potential future sources is "speculative and uncertain. None of them has completed CEQA review or obtained conditional use permits, and there is no commitment by the County to approve these projects."[21] The County also argues that the CDMAs signed by some potential sources are "preliminary agreements" only, with no binding aspects.[22]

Finally, the County argues that "[a]ll but one of the potential future CO_2 source projects have independent production purposes which generate CO_2 as a byproduct." (The exception, according to the County, being the DAC project.) The County states that although the oil field, alternative fuels, biomass conversion energy, cement, and steel projects "may [..]utilize underground CO_2 storage, the projects do not themselves have a carbon capture and storage (CCS) purpose."[23] The County also argues that "[t]he proposed project facilities are designed and sized to accommodate only the initial CO_2 source."[24]

For the above reasons, the County concludes the proposed Project satisfies the "independent utility" and related criteria of the piecemealing cases, i.e., the potential future CO_2 sources are not "crucial elements" or "integral parts" of the Project, completion of which would be "legally compelled" or "practically presumed" by completion of the Project.[25]

The County is wrong about the law, and about how the law applies to the facts of this Project.

First, the County is wrong on the legal standard and seems to confuse financial viability with independent utility. The fact that a project can be financially viable does not, on its own, mean it is not part of a larger project. Courts have looked at whether a project is a first step toward future development and whether a reviewed project legally compels or practically presumes completion of another action, but not into whether a project was independently financially viable.[26] The court in the *Banning Ranch* case, which the County relies on to argue it need not analyze future sources, does not examine the projects' financial viability. Rather, it looks into whether one project is a significant step towards the second (as is clearly the case here) and whether one project is built to induce the second one. On that question, the *Banning Ranch* court found that the first project did not induce the second because the second "has already been planned."[27] Clearly, this is not the case here.

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[19] Final REIR, Vol. 3, Response GR-1a at 7-17.
[20] Final REIR, Vol. 3, Response GR-1a at 7-17.
[21] Final REIR, Vol. 3, Response GR-1a at 7-17.
[22] Final REIR, Vol. 3, Response GR-1a at 7-18.
[23] Final REIR, Vol. 3, Response GR-1a at 7-18.
[24] Final REIR, Vol. 3, Response GR-1a at 7-15.
[25] Final REIR, Vol. 3, Response GR-1a at 7-18.
[26] *Banning Ranch Conservancy v. City of Newport Beach* (2012) 211 Cal. App. 4th 1209, 1223.
[27] *Id.* at 1226.

In the same way, the County's reliance on the idea of "production purpose" as a factor that is determinant of whether the Project's description is proper, or of whether an agency engaged in piecemealing, has no support in case law. The *Banning Ranch* court's discussion of projects' purposes focused on whether projects were "independently justified." Here, future sources are not independently justified, and the CTV I Project is clearly not justified without its sources. Contrary to the County's position, many future sources rely on CCS for their "production purpose." Blue hydrogen, as the County acknowledges, "must" use CCS for its production.[28] Biomass carbon removal and storage, as the name suggests, also includes a CCS element as part of its production. The CalCapture Project is described in the Final REIR as capturing CO_2 emissions for sequestration in one of CTV I's reservoirs and has no other purpose but that.[29] All other projects listed in the future sources list also depend on CCS for their "production purpose," or they would not be considered potential sources.[30]

Second, the facts show that under any applicable legal standard, the Final REIR fails to properly define the Project scope and is piecemealing the Project's review, because the Project's description and features make it clear it is part of a larger activity.

The most obvious evidence of the fact the Project is part of a larger activity is the number, size, and scope of the CO_2 reservoirs for which approval is sought. The County tries to minimize the fact that the Project is asking to approve massive CO_2 reservoirs, dismissing it as "potential waste." But the County does not explain why the Project is seeking to approve not one, but *two* CO_2 reservoirs, when clearly one reservoir is more than enough for the Project's declared purposes: at most, the initial source will send about 200,000 tons of CO_2 for storage yearly, leaving the vast majority of the 26R reservoir empty and free for more storage.[31] Moreover, the project description makes clear there is no economic, geographic, or logical reason to send CO_2 all the way to the second reservoir, A1/A2, which is further away and requires more pipeline and CO_2 infrastructure. In fact, the A1/A2 reservoir is completely redundant to the Project's declared purposes and needs.

According to the Final REIR, the gas collection "tie[s] in together in Section 26R just northwest of CGP-1" and the "capture, compression, and pumping facilities would be constructed adjacent to the existing CGP-1 facility."[32] All CO_2 injection and storage could therefore be accomplished in the 26R reservoir, where collection and compression are conducted anyway, and there is no reason to add miles of pipelines and more infrastructure to send the CO_2

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[28] Final REIR, Vol. 3, Response GR-1a at 7-18. See also: "'blue hydrogen', which represents 95% of current U.S. hydrogen production, depends on carbon capture and storage to receive CO_2 generated in the production process, which converts natural gas to hydrogen and CO_2." Final REIR, Vol. 3, Response GR-1b at 7-22.

[29] RDEIR, Vol. 1 at 3-15.

[30] See, e.g., John Donegan, *Kern Supervisors Approve Permits for First California Steel Mill in Decades* (Mar. 19, 2024), https://www.bakersfield.com/news/kern-supervisors-approve-permits-for-first-california-steel-mill-in-decades/article_c5fe7874-e64f-11ee-a88a-cfb2c60a69dc.html (reporting approval of a new still mill with carbon capture component).

[31] The 26R reservoir's capacity is 37.96 MMT. RDEIR, Vol. 1 at 4.8-19.

[32] RDEIR, Vol. 1 at 1-6.

further away to the A1/A2 reservoir. The fact the Project is seeking approval of the second reservoir shows that it “practically presumes” more sources will send CO_2 for storage.[33]

The County also argues that the “[t]he proposed project facilities are designed and sized to accommodate only the initial CO_2 source.”[34] This is evidently not true, and not supported by substantial evidence.

First, as described above, the fact that the Final REIR seeks to approve *two* huge storage reservoirs contradicts this claim.

Second, this argument is disproved by the fact that the original applications the Project proponent submitted to EPA included a hydrogen facility and a DAC facility as potential sources. On July 10, 2024, U.S. EPA published revised versions of the draft Class VI permits for the Project for public comment, noting that “the changes are limited to the removal of all references to the proposed carbon dioxide sources – Avnos Direct Air Capture Facility and Lone Cypress Hydrogen Facility.”[35] No changes were made to the Final REIR as a result of this change. That is, all Project components—including its size, wells, compression facilities, and pipelines—are the same now as they were when they were “designed and sized” to accommodate at least two more significant sources.

Finally, this statement contradicts the Final REIR’s own analysis: in the GHG analysis, 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. The table shows how yearly injection numbers will rise gradually from around 100k MT to well over two million MT during the Project’s life. If the Project is “designed and sized only” to accommodate the initial source, how can it account for over two million MT of injected CO_2? If future infrastructure and development are contemplated as part of the Project, the Final REIR fails to disclose them.

The County’s response also ignores its own plans for a “carbon management business park” (CMBP). That park, which will be located in Kern County and is described in a County report, envisions many of the same industries that will rely on CCS for operations, including DAC, biomass CO_2 removal and storage, and blue hydrogen.[36] This park, while still at the planning stage, is very likely a potential source for CO_2 that could fill CTV I’s huge carbon sink.

[33] *Banning Ranch Conservancy, supra*, 211 Cal. App. 4th at 1223.
[34] Final REIR, Vol. 3, Response GR-1a at 7-15.
[35] EPA, *Public Comments Sought on Class VI UIC Injection Well Carbon Storage Draft Permits* (July 2024) at 1.
[36] RDEIR, Vol. 2, App. K.2: Envisioning A Carbon Management Business Park.

Moreover, County officials seem to rely on the proposed CO_2 storage for the CMBP development. [37]

For the reasons above, as well as for all the reasons stated in our RDEIR Comments, it is clear that the Project is "the first step toward future development,"[38] and that "the reviewed project [. . .] practically presumes completion of another action."[39] These actions need to be analyzed under CEQA.

The County's argument that the Project's sources are too speculative to analyze is also unconvincing on the law or the facts.

Even if the County does not have final project applications or other ongoing environmental review processes to rely on in the analysis, the County is still expected to conduct a "good faith review." Failing to analyze *any* aspects and potential impacts of the Project's future sources, when they are inseparable aspects of the Project, cannot be regarded as a good faith analysis. When the County fails to include relevant information on future sources, the project description cannot be finite and stable as required under CEQA.[40] Moreover, the County appears to have deliberately delayed publishing the Notice of Preparation for the Lone Cypress hydrogen project, a potential source, to avoid "complicating" the Project review.[41] This is not what good-faith review looks like.

As described in our RDEIR Comments and as the County itself admits, information is available on the future sources. The County argues this information is "more limited than information the County must consider in evaluating potentially significant impacts in all environmental categories under CEQA."[42] But even if that is true, it still provides valuable information on at least some environmental categories, and a good faith review should include that information. Another example of information the County fails to acknowledge or include in its analysis is the information included in the CDMAs entered into by the Project's proponent. As the WZI Report acknowledges, though not binding, "information that may be addressed in a

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[37] See, e.g., Jake Bittle, *Inside a California Oil Town's Divisive Plan to Survive the Energy Transition* (May 15, 2024), https://grist.org/energy/taft-california-kern-county-carbon-capture/ ("Oviatt saw something even bigger in CRC's strategy, something that she thought could reverse the county's economic tailspin. She drafted a proposal for what she called a 'carbon management business park,' an interlinked complex of new factories that would produce hydrogen or steel — and store the carbon they emitted doing so in nearby oil fields."); Dept. of Energy, *Kern County Finds Economic Opportunities Beyond Oil and Gas Production in a "Carbon Management Business Park"* ("'The Carbon Management Business Park vision has been an amazing success. Besides providing hope for our communities, we have three companies, two in the valley area of Kern County near proposed CCS areas and one in the desert area of Kern County near rail that are working with consultants on plans to submit for areas up to 9,000 acres each. They all have indicated they have companies interested in locating in such a park,' says Oviatt.").

[38] *Banning Ranch Conservancy*, *supra*, 211 Cal. App. 4th at 1223.

[39] *Id.*

[40] *Sierra Club v. City of Orange* (2008) 163 Cal.App.4th 523, 533.

[41] Email from Lorelei Oviatt, Kern County Planning & Natural Resources Dept., *Re: Elk Hills Blue Hydrogen Parcel Map Waiver and CEQA* (Dec. 1, 2023).

[42] Final REIR, Vol. 3, Response GR-1b at 7-21.

CDMA could include the amount of CO_2 that may need to be sequestered, timelines for project feasibility completion, service or product pricing, and other ancillary services."[43] The County ignores this information.

Finally, the County ignores the information that can and should be available regarding the CalCapture project. As the Final REIR acknowledges, this project "would explore capturing CO_2 emissions from the Elk Hills Power Plant."[44] The Elk Hills Power Plant is an existing and operating power plant, owned by the Project proponent. Relevant information on this project is therefore available for review and should have been included in this analysis.

In addition to the failure to provide analysis regarding the Project's specific sources, the Final REIR fails to provide adequate analysis or support for the "Future Sources" list as a whole, or for the inclusion or omission of particular sources or classes of sources on that list. If the County could not analyze the specifics of all future sources, it needed to at least explain the rationale behind the specific industry categories that will be allowed to send CO_2 to the Project and analyze the impacts of allowing these industries to send CO_2 to the Project. The Final REIR does not include such a discussion, and the technical memorandum on sources provides only "a general description" of the types of industries.[45] Without any analysis or rationale to support the list, the list does not serve the basic function of environmental review to provide adequate information and analysis for the public and decisionmakers to evaluate the Project and its impacts.

Moreover, this review is necessary because this EIR is likely the only point at which that review will happen. The County argues in its Response to Comments that each project will undergo its own environmental review and planning process,[46] but such analysis would be conducted at the project level only. This EIR is the correct place for analysis of the question of which industries and sources should be allowed to send CO_2 to the CTV I facility for sequestration, and which development incentives are created by enabling that. Not all industries and CO_2 sources are appropriate for CO_2 capture implementation, and CO_2 capture has different outcomes and risks with different industries. In the context of capturing CO_2 from gas fields, for example, there are major differences between the carbon intensity of different gas fields that impacts CCS implementation.[47] The Final REIR has improperly failed to analyze and disclose the differences and their impacts.

The most recent update to the International Energy "Net Zero Roadmap" found that the part that CCS plays in the Agency's emissions reduction scenario "is smaller than in the 2021 version, particularly in the near term. This reflects slower technological and market development

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[43] Final REIR, Vol. 3, App. A-1: Economic Feasibility Analysis at 4.
[44] RDEIR, Vol. 1 at 3-15.
[45] RDEIR, Vol. 1 at 3-13.
[46] RDEIR, Vol. 1 at 3-13.
[47] See, e.g., IEEFA, CCS *Hype and Hopes Sinking Fast* (Oct. 2024) at 5, https://ieefa.org/resources/ccs-hype-and-hopes-sinking-fast.

progress than envisaged in 2021 and stronger electrification prospects."[48] The Final REIR has failed to account for the diminishing role of CCS as a climate solution, and for the reasons for this decline and how they affect potential CO_2 sending sources and their inclusion in the "Future Sources" list.

The discussion should also have included the impacts related to each industry on the list, including the hazards associated with certain facilities[49] and the impacts of extending the life of fossil fuel sources, as described in our RDEIR Comments. All these questions should have been answered in this EIR to the extent possible, since the County is unlikely to address them in project-specific environmental review for the facilities that will ultimately send CO_2 to the Project's storage facility.

Finally, it is problematic that the measure that sets the parameters for the "Future Sources" list is a land use mitigation measure, MM 4.11-7. The County argues in the Response to Comments that because the Measure "deals with sources and locations it is appropriate for inclusion in land use and conformance with Kern County policies," and further explains that "this measure provides additional layer of protections to ensure indirect conflicts with applicable plans would not result from implementation of the Project."[50] The fact that the rules on allowed sources and their geographic location are part of a land use mitigation further emphasizes the lack of analysis and evidence to support the "Future Sources" list. The list and its rules may serve to mitigate some land use conflicts, mostly by giving the County some control over land use decisions, but it is not based on any evidence or analysis relating to any other impacts that stem from the decision to include certain industries in the list. These impacts include impacts on air, greenhouse gases, water supply, pipeline safety and other hazards, geology, public health and environmental justice, and biological resources.

Alternatively, each of the comments above supports the conclusion that the cumulative impacts analysis is flawed because it fails to adequately consider CO_2 sources as cumulative or connected projects that may result in cumulative impacts, when incremental impacts of the Project are considered together with these other activities.[51] If the impact of those activities is not included in the project scope, it certainly should be included in the analysis of cumulative impacts, and the failure to do so violated CEQA, as discussed further below.[52]

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[48] Internat. Energy Agency, *Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach,* 2023 update, at 55, https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach.
[49] See, e.g., Luz Pena, *Hydrogen Explosion Shakes Santa Clara Neighborhood*, ABC News (June 2, 2019), https://abc7news.com/santa-clara-explosion-in-chemical-fire/5326601/.
[50] Final REIR, Vol. 3, Response 3-175 at 7-152 to 7-153.
[51] "The cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects." CEQA Guidelines, § 15355.
[52] See Section V.I below; cf. Final REIR, Vol. 3, Response GR-10a at 7-91 (arguing that "[i]f future CO_2 source projects were part of the proposed project itself, as commenters claim, their impacts would be project impacts, not contributions to cumulative impacts. Conversely, comments on cumulative impacts from future CO_2 source projects are premised on the assumption that these are separate projects, not part of the proposed project.").

B. The Final REIR Fails to Disclose or Address the Impacts of CRC's Merger with Aera Energy.

In response to our RDEIR Comments on the County's failure to address CRC's merger with Aera Energy and the merger's impacts on CTV I, the County added a paragraph acknowledging the merger and stating "[b]oth projects [TerraVault I and Aera's CarbonFrontier] are being processed separately, have no shared facilities and are not dependent on the other for operations." No analysis was added to the Final REIR.

This response ignores yet again CEQA's mandate to analyze reasonably foreseeable projects that are "significant in that it will likely change the scope or nature of the initial project or its environmental effects."[53] The County ignores CRC's statement that the merger "doubles CRC's premium CO_2 pore space in the San Joaquin Basin"[54] and how that may affect the Project's scope, and the conclusions are not supported by evidence. While Aera has recently requested that the County Planning Commission hearing on its CarbonFrontier CCS project be postponed to a later date, the project is still "reasonably foreseeable" and the project application was not withdrawn, thus the County should still analyze its impacts together with CTV I.

II. THE FINAL REIR FAILS TO ANALYZE GROWTH-INDUCING IMPACTS

CEQA requires the Final REIR to describe growth-inducing impacts of the CTV I Project,[55] including ways in which the Project could directly or indirectly foster economic growth that could lead to an adverse physical change to the environment.[56] The REIR fails to do so, focusing instead only on the Project's limited potential to create employment opportunities, and concluding no significant impact will occur.[57]

In the Response to Comments, the County defends its analysis by arguing that while the Project's objectives include "economic development," "this would be accomplished through the 0 to $400 per acre pore space fee being paid by the Applicant to the County, and not through a greater economic impact, as implied by the comment."[58]

The Final REIR thus continues to violate the duty under CEQA to discuss the ways in which a proposed project could foster *economic growth*, directly or indirectly.[59] The fact that the County plans to impose a fee on the Project does not negate the fact that the Project will foster economic development by creating an incentive to build CCS-reliant development, and CEQA

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[53] *Laurel Heights, supra*, 47 Cal.3d at 396.
[54] CRC and Aera, Press Release, *Expanding Our Leading Energy Platform* (Feb. 24, 2023) at 6.
[55] Pub. Resources Code, § 21100(b)(5); CEQA Guidelines, § 15126(d).
[56] CEQA Guidelines, §§ 15126.2(d), 15064(e); *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1205.
[57] RDEIR, Vol. 1 at 5-8.
[58] Final REIR, Vol. 3, Response 3-025 at 7-123.
[59] CEQA Guidelines, § 15126.2(e).

requires the County to "[d]iscuss the ways in which the proposed project could foster economic […] growth" and analyze the potential impacts of that growth.[60]

The RDEIR Comments highlight the significant economic development potential of the Project, including a report that found significant fiscal, economic, and employment benefits from the potential development of a carbon management park.[61] This is further emphasized by the WZI Report, which demonstrates that carbon sequestration can be highly profitable, with substantial earnings from tax and GHG credits alone.[62] Moreover, the pore space fee the County intends to levy on the Project is required regardless of injection schedule.[63] This means the Project proponent will have an even stronger economic incentive to attract more CO_2 sources and create more growth. This growth, and any potentially significant environmental impacts of that growth, remain unanalyzed in the EIR, contrary to CEQA's requirements. This failure, in turn, links directly back to the failure to adequately analyze Project CO_2 sources, either as part of the Project itself, or as projects that contribute to cumulatively significant impacts of the Project—especially given that those sources will be located in Kern County.

III. THE FINAL REIR FAILS TO PROVIDE ADEQUATE PROJECT OBJECTIVES

The Final REIR does not provide an adequate set of project objectives, notwithstanding the County's protestation to the contrary. While the County makes much of the word "sought" in CEQA Guidelines section 15124,[64] the EIR is necessarily a public document evaluating public costs and benefits. This approach is consistent with agency best practices as articulated by California's Office of Planning and Research (OPR). OPR and the federal Council on Environmental Quality have noted in guidance, for example, that the "function" of CEQA's statement of project objectives—and the analogous requirement of NEPA—is "to explain why the project is being considered and assist in the decision-making process." The agencies also noted that "the project objectives help determine which alternatives are considered in the environmental analysis," and that where multiple agencies are involved in project approval, "[d]ifferent agencies considering a project may have different missions or authorities, which in turn could create different goals for a single project."[65]

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[60] CEQA Guidelines, § 15126.2(e). See also *Clover Valley Found. v. City of Rocklin* (2011) 197 Cal. App. 4th 200, 227 (more detailed analysis is required when the purpose and nature of a project is to facilitate additional development).
[61] 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.
[62] Final REIR, Vol. 3, App. A-1: Economic Feasibility Analysis.
[63] See, e.g., RDEIR, Vol. 1 at 1-63 ("A payment of from $0 up to $400 per net acre shall be paid annually for all acres in the approved Conditional Use Permit regardless of phased implementation of facilities or the project injection schedule.").
[64] CEQA Guidelines, § 15124 (requiring "[a] statement of the objectives sought by the proposed project" and noting a statement of project objectives "may discuss the project benefits").
[65] U.S. Council on Environmental Quality & Cal. Governor's Office of Planning & Research, *NEPA and CEQA: Integrating Federal and State Environmental Reviews* (Feb. 2014), https://opr.ca.gov/ceqa/docs/NEPA_CEQA_Handbook_Feb2014.pdf.

Nowhere do either the Guidelines or this (or other) guidance suggest this is different for agency-developed projects than for projects that involve issuing a permit for a project with a private proponent, as the County suggests. All these factors instead suggest that a statement of project objectives is very much a statement of public, rather than private, objectives.

IV. THE FINAL REIR FAILS TO ANALYZE ADEQUATE ALTERNATIVES

The Final REIR does not correct any of the flaws previously identified in the Recirculated Draft EIR's alternatives analysis, nor does it persuasively demonstrate the alternatives analysis is adequate.

A. The Final REIR 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 Final REIR's alternatives analysis still 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.[66] The inadequacy of the Response to Comments addressing all three of these points are addressed elsewhere in these comments.

One point bears more discussion, however. The Final REIR's alternatives analysis still asks its readers to accept an internal inconsistency that reflects a fundamental failure in the underlying Project GHG analysis and conclusions. Response GR-9e states:

> While the GHG impact analysis concluded that the "contribution to greenhouse emission due to unknown release of emissions or stops to injection for monitoring failures remains significant and unavoidable" (RDEIR, p. 4.8-26), the No Project Alternative analysis compares the unchanged GHG baseline with no project to the expected "environmental effects which would occur if the project is approved" (CEQA Guidelines §15126.6(e)(3)(B)), where the project is operating to capture and store CO_2. In that comparison, where the RDEIR states "impacts to GHGs would be greater" under the No Project Alternative (RDEIR, p. 6-17), the statement is intended to convey that the No Project Alternative will have a poorer GHG outcome (with no change from baseline conditions) than the proposed project operating a carbon capture and storage facility.[67]

This discussion fails to address the paradox at the crux of the analysis: the County has concluded that the Project's GHG emissions will result in unavoidable significant impacts. The Project, then, necessarily has a greater GHG impact than the alternative that the lead agency has concluded will result in no significant impacts. Yet here, the County has instead found, in conclusory terms, that the outcome of the No Project Alternative will be "poorer" based on an

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[66] See CEQA Guidelines, § 15126.6; Pub. Resources Code, § 21002; *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 738–39; *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 733.

[67] Final REIR, Vol. 3, Response GR-9e at 7-90.

apparently idiosyncratic, baseless definition of "poorer" that ignores the County's own significance finding. The County may not simply assume away its own finding of significant impact (and related evidence of the possibility there will be future "unknown release of emissions") in favor of an unmoored conclusion that the Project will result in less impact than the No Project Alternative because, in the County's opinion, the outcome of the No Project Alternative will be "poorer."

These analytical failures render the Final REIR's alternatives analysis deficient.[68] Response GR-9e actually exacerbates the informational deficiency already noted, since it doubles down on incoherent, internally inconsistent, and confusing analysis that impedes the ability of the public or a decisionmaker to compare the alternatives meaningfully.

B. The Final REIR Fails to Adequately Consider a Reasonable Range of Alternatives.

The Final REIR neither corrects nor persuasively addresses the prior comments showing the range of alternatives is deficient.[69]

As previously noted, the Final REIR 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 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 Final REIR fails to consider.

The County appears to argue that it has no obligation to study any such alternatives, including but not limited to the "Drilling Ban on All Lands 'Leave It in the Ground' Alternative," in detail because any reduction in oil extraction would constitute a "taking" under the Fifth Amendment to the U.S. Constitution. It is odd that a local government would be making arguments that take such an unnecessarily cramped view of its own police power. Moreover, the County's legal argument completely ignores the long history of California's cities and counties limiting oil extraction and related activities with approval of the courts,[70] as well as the California Legislature's recent enactment of legislation affirming that "a local entity may, by ordinance, prohibit oil and gas operations or development in its jurisdiction or impose regulations, limits, or prohibitions on oil and gas operations or development that are more protective of public health, the climate, or the environment than those prescribed by a state law, regulation, or order."[71] The County also ignores the likelihood that the investment-backed expectations of mineral rights holders have already been met and their investment may be

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[68] See CEQA Guidelines, § 15126.6; *Laurel Heights, supra*, 47 Cal.3d at 406.
[69] *Id.; San Joaquin Raptor*, *supra*, 27 Cal.App.4th at 736–37.
[70] See, e.g., *Beverly Oil Co. v. City of Los Angeles* (1953) 40 Cal. 2d 552; *Hermosa Beach Stop Oil Coal. v. City of Hermosa Beach* (2001) 86 Cal. App.4th 534.
[71] Assembly Bill 3233 (2024), Pub. Resources Code, § 31061(a), added by Stats. 2024, ch. 550, § 2, https://legiscan.com/CA/text/AB3233/2023.

considered fully amortized within a short timeframe, which would defeat a takings claim.[72] Regardless, the County may not summarily dismiss the need to evaluate a potential alternative based on speculative legal analysis. And the County does not even consider any reduced-drilling alternatives.

Nor does the County adequately justify its summary rejection of the "Replacement of Elk Hills Power Plant with Renewable Energy Alternative" or similar alternatives that would reduce or phase out the use of gas-fired power generation in relation to the oil field. The County's protestations are not evidence.

C. The Final REIR's Discussion of Alternative 1, the "No Project" Alternative, is Inadequate Under CEQA.

The Final REIR's "no project" alternative discussion is still inadequate under CEQA because it still fails to include basic information about the no-project alternative.[73]

The County attempts to distinguish *Save the Hill Group v. City of Livermore*, where 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.[74] But it remains true that the Final REIR lacks any "factually based forecast of the environmental impacts of preserving the status quo"[75] and instead, includes a cursory narrative discussion, with no supporting evidence or analysis. The EIR makes no meaningful attempt to quantify or to provide evidence to support any of its analysis of the "no project" alternative, even though the comparison between impacts of the proposed project and the no-project alternative is an essential component of an adequate EIR. There is simply no public disclosure at all, but instead just discussion untethered to facts. This failure renders the entire alternatives analysis deficient as lacking in substantial evidence. It is unclear, for example, even whether Alternative 1 reflects decreasing oil field operations over time, or ending oil field operations by 2045 or 2053 or any other year.

Additionally, as discussed above, the analysis of the no-project alternative is still inadequate because the comparison between the no-project alternative and the proposed Project is misleading, inconsistent, and incoherent. Response GR-9e actually exacerbates the problem already identified, by doubling down on the EIR's bizarre characterization of Alternative 1 as having greater GHG impacts than the Project, despite the analytical conclusion that the Project will have unavoidable significant impacts, while the no-project alternative will not.

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[72] See, e.g., Baker & O'Brien, *Capital Investment Amortization Study for the City of Culver City Portion of the Inglewood Oil Field* (May 29, 2020), https://www.culvercity.org/files/assets/public/v/1/documents/city-manager/inglewood-oil-field/bakerobrienreportandexhibi.pdf (concluding that "amortization of capital investment ('ACI') in oil and gas production facilities" within Culver City's portion of the Inglewood Oil Field occurred "within four years" of the current operator's purchase of the oil field; that "ACI for individual wells is typically achieved within a few years" for wells drilled since 1977; and that "wells drilled prior to 1977 achieved ACI within the first several years of operation").

[73] See Cal. Code Regs., tit. 14, § 15126.6.

[74] *Save the Hill Group v. City of Livermore* (2022) 76 Cal.App.5th 1092, 1113.

[75] *Ctr. for Biological Diversity v. Dept. of Fish & Wildlife* (2015) 234 Cal.App.4th 214, 253.

D. The Final REIR Fails to Adequately Describe or Analyze Alternatives 2 and 3.

The Final REIR neither corrects nor justifies the EIR's inadequate discussion of the two "action" alternatives, DAC (Alternative 2) and nature-based carbon storage (Alternative 3); that discussion is both lacking in substantial evidence to support it, and inadequate as a matter of law to meet CEQA's requirements. "The EIR shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project."[76] But here, the Final REIR, including Response GR-9f, still not only fails to describe either alternative with specificity, but also still fails to disclose or even meaningfully attempt to discuss the projected impacts of either alternative.[77]

While the County notes that "no specific projects have been proposed and the analysis is necessarily hypothetical,"[78] presumably as a reason for failing to specify the parameters of the alternatives, this cannot excuse the County's failure to actually specify those parameters or to study the alternatives' impacts. But this is true of almost all alternatives studied in EIRs. Alternatives analysis under CEQA commonly develops and analyzes "hypothetical" alternatives, which often are articulated and developed within the EIR process rather than separately proposed and articulated elsewhere. The County has made a choice—a choice that is not defensible—to fail to provide any clear description, much less analysis, of the alternatives it has selected to analyze.

First, Alternative 2, the EIR's vague and cursory discussion of the generalized features of DAC technology and facilities—without any reference to how those features might comprise an alternative to this Project—does not even come close to an analysis of an alternative to the proposed Project.[79] As noted previously, there is no substantial evidence—indeed, no evidence at all—supporting the Final REIR's comparison of the Project with the DAC alternative. The "hypothetical" nature of this alternative does not excuse the County's obligation to describe and analyze it.

Second, Alternative 3, the "Nature Based Carbon Storage" alternative, also still fails to meaningfully specify any of the features of the alternative, much less its impacts. While the Final REIR sets forth some general ideas about what types of features this potential alternative might include, the alternative remains completely unformed and unanalyzed.[80] Response GR-9f refers back to the EIR's 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."[81]

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[76] CEQA Guidelines, § 15126.6. See *San Joaquin Raptor*, *supra*, 27 Cal.App.4th at 738–39; *Kings County Farm Bureau*, *supra*, 221 Cal.App.3d at 733.
[77] Final REIR, Vol. 3, Response GR-9f at 7-90 to 7-91.
[78] Final REIR, Vol. 3, Response GR-9f at 7-90.
[79] RDEIR, Vol. 1 at 6-17 to 6-20 (containing the Recirculated Draft EIR's discussion of Alternative 2, in full).
[80] RDEIR, Vol. 1 at 6-20 to 6-21 (containing discussion of Alternative 3, in full).
[81] RDEIR, Vol. 1 at 6-20.

The Response unintentionally illustrates just how little work went into analyzing this alternative, citing only to a "calculator" on a webpage entitled "How Much Carbon Does a Tree Capture" that is run by the social benefit corporation 8 Billion Trees.[82] There is no methodology cited, nor any data, but merely a link to the website, which includes a very rudimentary web-based tool that it calls "Measuring Tree Benefits," with three input fields: "What Is the Circumference of the Tree?" "How Many Trees?" and "How Many Years Old?" This "calculator," a rough estimating tool similar to other simple web-based "calculators" for public and retail use, is obviously not designed to support a rigorous analysis of an alternative to a massive commercial carbon storage project. And the County does not reveal its inputs into the calculator, in any event. Overall, the citation here reveals just how shoddy and baseless even the minimal "analysis" is, in turn revealing the lack of any serious, good-faith effort to evaluate this alternative.

In conclusion, none of the three alternatives presented in the Final REIR, nor all three taken together, meets the minimum requirements of CEQA for an adequate analysis of alternatives. The range of alternatives is unsupported and inadequate, and the discussion of each alternative is not informationally adequate, supported by substantial evidence, or analytically sound.

V. THE FINAL REIR FAILS TO ANALYZE AND MITIGATE SIGNIFICANT IMPACTS

As we pointed out in previous comments on the original December 19, 2023 Draft EIR and the June 4, 2024 Recirculated Draft EIR for the CTV I Project, the County's analysis fails to provide an adequate or lawful review of the Project's impacts and appropriate mitigation measures. The Final REIR is invalid because it fails to respond substantively to the concerns raised by Commenters, and the County's analysis remains flawed.

In addition, the Final REIR's mitigation measures do not satisfy CEQA's legal requirements. The measures continue to be vague, ineffective, unenforceable, and impermissibly deferred without any standards. The County also fails to abide by CEQA's mandate requiring that proposed mitigation measures must be "fully enforceable" through permit conditions, agreements, or other legally binding instruments.[83] CEQA requires that any proposed mitigation must also provide assurance that such implementation will in fact occur.[84] The County fails to provide such assurances for several proposed mitigation measures.

Finally, Commenters note that the County appears to have made substantive changes to its analysis and mitigation measures solely in the Staff Report it released for the September 12, 2024 Planning Commission hearing for the Project, without making corresponding updates to the relevant portions of the Final REIR.[85] The Final REIR's failure to reflect accurate and complete

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[82] Final REIR, Vol. 3, Response GR-9f at 7-91; How Much Carbon Does a Tree Capture, https://8billiontrees.com/carbon-offsets-credits/carbon-ecological-footprint-calculators/how-much-carbon-does-a-tree-capture/.
[83] Pub. Resources Code, § 21081.6(b); CEQA Guidelines, §15126.4(a)(2).
[84] *Anderson First Coalition v. City of Anderson* (2005) 130 Cal.App.4th 1173, 1186–87.
[85] See, e.g., Kern County Planning & Nat. Resources Dept., Planning Com., Staff Report (Sept. 12, 2024) (hereafter "Staff Report") at 36–40.

information regarding the County's analysis and mitigation for the Project prevents the public from fully participating, as required by CEQA, and further renders the Final REIR inadequate as an informational document.

A. The Final REIR's Analysis and Mitigation of Air Quality Impacts is Inadequate.

1. The County should address the possibility that CO_2 will be delivered by heavy-duty truck and/or rail and adopt appropriate mitigation.

In the Notice of Preparation/Initial Study, the County stated 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."[86]

The Final REIR states that, under the current Project description, CO_2 will be transported exclusively "through a 16-inch underground facility pipeline," meaning truck trips therefore will be limited to "operation and maintenance activities."[87]

Mitigation Measure 4.11-7 requires that for all CO_2 to be injected at the Project—including CO_2 from future sources—the source of CO_2 must provide proof of CEQA review for the source facility and for any pipelines used to transport the CO_2 to the Project site.[88]

MM 4.11-7 is inadequate given the County's previous acknowledgment that the transport of CO_2 from new industrial sources to the Project might be accomplished by truck or rail as well as by pipeline.[89] Should the Project intend to start accepting CO_2 via truck or rail, a thorough assessment of impacts and the adoption of all feasible mitigation is crucial because these forms of transportation may cause direct and cumulative impacts. Potential impacts from transporting CO_2 by truck and/or rail include but are not limited to impacts upon air quality, energy demand and consumption, greenhouse gas emissions, hazards and hazardous materials, noise, and traffic.

For these reasons, MM 4.11-7 should have been revised to specify that all sources of CO_2 must provide written evidence demonstrating that air pollution emissions and other impacts associated with transport of the CO_2 from its source to the Project—whether by pipeline or some other means—has been addressed in an Environmental Impact Report for compliance with CEQA.

[86] *Notice of Preparation/Initial Study* at 4.
[87] Final REIR, Vol. 3, Response 3-016 at 7-121 and Response 3-045 at 7-126 to 7-127.
[88] RDEIR, Vol. 1 at 1-58 to 1-59, 4.11-53.
[89] *Notice of Preparation/Initial Study* at 4.

2. The Final REIR fails to adequately address the national ambient air quality standards for $PM_{2.5}$.

On February 7, 2024, U.S. EPA strengthened the annual health-based national ambient air quality standard (NAAQS) for fine particulate ($PM_{2.5}$) from a level of 12 micrograms per cubic meter to 9 micrograms per cubic meter.[90]

According to the County's Response to Comments, Table 4.3-1 has been revised to reflect the updated annual $PM_{2.5}$ NAAQS.[91] This change is not reflected, however, in Section 7.1.3 of the Final REIR, which purportedly "includes a listing of all errata/revisions made to the text of the Draft Recirculated Environmental Impact Report (DREIR)."[92]

Putting aside the Final REIR's inconsistent treatment of Table 4.3-1, merely updating Table 4.3-1 is not sufficient. Table 4.3-2 addresses the "Attainment Status for the San Joaquin Valley Air Pollution Control District,"[93] and relevant text should have been updated there as well. Table 4.3-2 notes that "[t]he SJV is designated nonattainment for the 1997, 2006, and 2012 $PM_{2.5}$ standard" but does not mention the new 2024 standard.[94] Although EPA has not yet issued official attainment designations, EPA has noted that air quality in Kern County currently does not meet the new standard[95] and is not expected to meet it in 2032.[96] This should be noted on Table 4.3-2.

Further, as Commenters noted previously, the Final REIR should also address the clear implication of the new annual $PM_{2.5}$ NAAQS: the San Joaquin Valley Air Pollution Control District (Air District) will have to institute further restrictions on polluting projects and activities throughout the San Joaquin Valley airshed, including in Kern County.[97] The County has refused

[90] 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.
[91] Final REIR, Vol. 3, Response GR-6a at 7-51.
[92] Final REIR, Vol. 3 at 7-2; 7-5 to 7-6 (showing only one change to Section 4.3 on Air Quality).
[93] RDEIR, Vol. 1 at 4.3-8.
[94] RDEIR, Vol. 1 at 4.3-8.
[95] 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).
[96] 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.
[97] Lazo, *California's Pursuit of Clean Air Just Got Much Harder: New Soot Standards Set*, CalMatters (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.

to make such an acknowledgment, arguing that "[o]nly after the attainment designation process has played out and the regulatory agencies have had an opportunity to assess what actions may be necessary will it be possible to know what further regulatory actions, if any may follow."[98] While it is true that specific future regulatory actions are not known at this time, it is indisputable that the Air District will have to enact further restrictions to improve air quality and meet the new, lower standard. Before a new, significant source of air pollution like the Project is built, decisionmakers and the public should be apprised of this inevitability.

3. The Final REIR fails to make clear the full danger posed by increased $PM_{2.5}$ emissions.

a. The Final REIR fails to disclose that there is no safe level of exposure to $PM_{2.5}$.

The Final REIR's discussion of the health effects of $PM_{2.5}$ should reflect the latest science on health effects, as summarized by U.S. EPA in its standard-setting decision. An update to the Final REIR's discussion of the health consequences of $PM_{2.5}$ is necessary because CEQA requires that an EIR conduct "an analysis that connect[s] the air quality effects to human health consequences."[99]

Crucially, U.S. EPA has concluded that currently available evidence indicates there is no safe level of exposure to $PM_{2.5}$.[100] The County dismisses this conclusion, arguing that U.S. EPA's statement "occurs in the section entitled 'Uncertainties in the Health Effects Evidence' . . . and in context is intended to identify uncertainty in interpreting evidence from epidemiological studies, rather than a [sic] stating conclusion on health effects."[101]

The County's response is absurd. U.S. EPA's statement is not meant to suggest that the evidence on the health effects of $PM_{2.5}$ is uncertain. To the contrary, U.S. EPA is identifying a challenge in setting an ambient air quality standard (i.e., a "safe level") for an air pollutant that science indicates is not safe at any level. It is for this reason U.S. EPA issued its finding that "epidemiologic studies conducted to date do not identify a population-level threshold below which it can be concluded with confidence that $PM_{2.5}$-related effects do not occur."[102]

Notably, beyond U.S. EPA's most recent statements in the 2024 annual $PM_{2.5}$ NAAQS rulemaking, it is well established that there is no safe level of $PM_{2.5}$ exposure—a conclusion

[98] Final REIR, Vol. 3, Response GR-6a at 7-51.
[99] *Sierra Club v. County of Fresno* (2018) 6 Cal.5th 502, 522.
[100] 89 Fed. Reg. 16238, 16249.
[101] Final REIR, Vol. 3, Response GR-6a at 7-51.
[102] 89 Fed. Reg. 16238, 16249.

reached by a fifteen-scientist panel convened by the National Academy of Sciences[103] and endorsed in judicial decisions.[104]

The County also asserts that, "[i]n any event, the Ramboll Report provides an expert opinion that the statement cited by commenters does not warrant a revision to the discussion of $PM_{2.5}$ health effects contained in the RDEIR."[105] This is inaccurate. Nowhere does the Ramboll Report address this issue. In any event, the adequacy of an EIR's discussion of an impact is a question of law; it is not a concern that can be waived away with the opinion of a technical consultant.[106]

b. The Final REIR fails to address how PM2.5 exacerbates illness and death from COVID-19.

The Final REIR's discussion of the health effects of $PM_{2.5}$ fails to adequately address "the nature and magnitude"[107] 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.[108] Indeed, one recent

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[103] Nat. Academy of Sciences, *Global Sources of Local Pollution: An Assessment of Long-Range Transport of Key Air Pollutants to and from the United States* (2010) at 17 (finding there is "no evidence of a threshold below which no adverse health impacts are observed" for exposure to particulate matter), https://nap.nationalacademies.org/catalog/12743/global-sources-of-local-pollution-an-assessment-of-long-range.

[104] See e.g., *United States v. Westvaco Corp.*, No. CV MJG-00-2602, 2015 WL 10323214, at *9 (D. Md. Feb. 26, 2015) ("majority scientific consensus, accepted by the Court, is that the harm from exposure to $PM_{2.5}$ is linear, and there is no known threshold below which $PM_{2.5}$ is not harmful to human health").

[105] Final REIR, Vol. 3, Response GR-6a at 7-51.

[106] *Sierra Club*, *supra*, 6 Cal.5th at 514 ("[W]hether a description of an environmental impact is insufficient because it lacks analysis or omits the magnitude of the impact is not a substantial evidence question. A conclusory discussion of an environmental impact that an EIR deems significant can be determined by a court to be inadequate as an informational document without reference to substantial evidence.").

[107] *Id.* at 522.

[108] 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; 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.

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.[109]

The County has declined to mention that $PM_{2.5}$ exposure increases COVID-19 morbidity and mortality, arguing that "[a]t present there is no COVID emergency declaration by the State of California and the flu, RSV and the common cold have the same relationship to $PM_{2.5}$ exposure."[110] But whether or not there is a COVID emergency declaration in place, it does not change the fact that increased COVID-19 morbidity and mortality is a health effect of $PM_{2.5}$ that must be disclosed. To the extent that $PM_{2.5}$ exposure also meaningfully increases illness and death from the flu, RSV, and the common cold—this should be disclosed as well.

Notably, in previous EIRs, the County has properly apprised decisionmakers and the public regarding how $PM_{2.5}$ exacerbates illness and death from COVID-19. For example, in its CEQA review for the County's oil and gas permitting ordinance, the County acknowledged:

> A small increase in long-term exposure to $PM_{2.5}$ has been found to lead to an increase in the death rate of COVID-19 (Harvard School of Public Health 2020). The study suggests that long-term exposure to $PM_{2.5}$ is associated with higher COVID-19 mortality rates, even after adjustment for a wide range of socioeconomic, demographic, weather, behavioral, epidemic stage, and healthcare-related confounders. Long-term exposure to $PM_{2.5}$ emissions may also add to the potential susceptibility for COVID-19. People of color may live in areas already burdened by air pollution (NRDC 2014). People of color may also have a higher risk of getting sick or dying from COVID-19 (California Department of Public Health 2020).[111]

Similar language reflecting the most recent studies on $PM_{2.5}$ exposure and COVID-19 morbidity and mortality should be added to the Final REIR.

4. The Final REIR fails to adopt all feasible mitigation to control fugitive dust.

The Final REIR acknowledges that PM_{10} is largely emitted as fugitive dust, often generated by construction, demolition, excavation, extraction, and/or other earthmoving activities.[112] Such activities—as well as vehicle traffic, another source of PM_{10}—will occur at the CTV I Project site, and the Final REIR concludes that the Project's construction and

[109] 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.
[110] Final REIR, Vol. 3, Response 3-051 at 7-127.
[111] Kern County Planning & Nat. Resources Dept., *Draft 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) at 4.3-43.
[112] RDEIR, Vol. 1 at 4.3-14, 4.3-38 to 4.3-39.

operational activities will cause a significant increase in PM_{10} emissions.[113] Consequently, all feasible mitigation for PM_{10} must be adopted.

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."[114] The Measure further specifies 14 specific "dust control measures [that] shall be implemented."[115]

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. As Commenters noted previously, MM 4.3-2 fails to require all mitigation measures contemplated by the Air District's Regulation VIII and, in some cases, contradicts stricter requirements set forth in the regulation.[116]

The County's Response to Comments does not meaningfully address or resolve the unlawful shortcomings of MM 4.3-2. The County merely notes that paragraph 12 of the measure requires the Project to implement "Other fugitive dust control measures as necessary to comply with [Air District] Rules and Regulations" and that "approval of the Fugitive Dust Control Plan from [the Air District] is included as a requirement for the implementation of the project."[117]

As written, MM 4.3-2 does not represent all feasible mitigation for several reasons.

First, if the measure is intended to merely require that the Project abide by all Air District rules and regulations, it should just say so explicitly—rather than identifying requirements selectively—which will cause confusion and undermine compliance and effectiveness.

Second, MM 4.3-2 cannot stand as written because some of the requirements *contradict* Air District requirements. For example, paragraph 10 of MM 4.3-2 states that "Traffic speeds on unpaved roads shall be limited to 25 miles per hour."[118] Air District rules, however, specify that traffic speeds on unpaved roads should be limited to 15 miles per hour, with speed limit signs posted.[119]

Third, contrary to the County's assertion, the Final REIR does not explicitly require the Air District to review and approve the Project's Fugitive Dust Control Plan. Rather, the Final REIR merely states that such a plan must be "develop[ed] and implement[ed] . . . in compliance with San Joaquin Valley Air Pollution Control District fugitive dust suppression regulations."

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[113] RDEIR, Vol. 1 at 4.3-63 to 4.3-68.
[114] RDEIR, Vol. 1 at 4.3-58.
[115] RDEIR, Vol. 1 at 4.3-58 to 4.3-59.
[116] RDEIR Comments at 35–37. The Air District's Regulation VIII and its constituent rules are described in RDEIR 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/.
[117] Final REIR, Vol. 3 at 7-57.
[118] RDEIR, Vol. 1 at 1-29, 4.3-59; Final REIR, Vol. 3, Response GR-6d at 7-57.
[119] Rule 8021, section 5.3.

Further, although the County asserts that "the approval of the Fugitive Dust Control Plan from [the Air District] is included as a requirement for the implementation of the project," citing section 3.8 of the Recirculated Draft EIR,[120] section 3.8 uncommittedly lists "discretionary and ministerial permits/approvals" that "the project proponent *may* need to obtain."[121]

Fourth, in addition to explicitly requiring Air District approval, MM 4.3-2 must be amended to 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."[122]

Finally, MM 4.3-2 is inadequate because merely requiring compliance with existing Air District rules and regulations is not sufficient to comply with CEQA or the Health and Safety Code. In addition to CEQA's requirement that projects adopt all feasible mitigation measures,[123] the Health and Safety code mandates that CCUS projects like CTV I "include . . . [s]trategies to minimize, *to the maximum extent technologically feasible*, co-pollutant emissions from facilities where CCUS or CDR technology is deployed" to ensure there is no "adverse impact on local air quality and public health, particularly in low-income and disadvantaged communities."[124]

Here, the County has neglected to consider whether there are feasible measures to control fugitive dust that would further reduce harmful air emissions beyond the Air District's minimum requirements. Commenters' previous comments suggested several such feasible measures that the County has failed to address, let alone establish that they are infeasible.[125]

5. The Final REIR does not provide adequate mitigation to protect sensitive receptors.

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

Aimed at mitigating air quality impacts on sensitive receptors, MM 4.3-8 sets forth the following requirements for fence line monitoring to detect harmful air pollutants:

> 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

[120] Final REIR, Vol. 3, Response GR-6d at 7-57.
[121] RDEIR, Vol. 1 at 3-43 to 3-44 (emphasis added).
[122] *King & Gardiner Farms, LLC v. County of Kern* (2020) 45 Cal.App.5th 814, 860., quoting *POET, LLC v. Cal. Air Resources Bd.* (2013) 218 Cal.App.4th 681, 738.
[123] Pub. Resources Code, § 21002; CEQA Guidelines, § 15126.4(a)(1).
[124] Health & Safety Code, § 39741.1(a)(3)(A).
[125] *Compare* RDEIR Comments at 36–37 *with* Final REIR, Vol. 3, Response GR-6d at 7-56 to 7-57 and Response 3-058 at 7-128 (no response).

> 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.[126]

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 fence line monitoring plan to detect elevated pollution levels.

Unfortunately, MM 4.3-8 does nothing more than generically require development and approval of a future fence line monitoring plan. The mitigation measure fails to identify any performance standards to be used to develop the plan and, even more troublesome, neglects to identify performance criteria for the mitigation to be instituted if the monitoring identifies harmful levels of air pollution. This open-ended and therefore potentially meaningless promise of a mitigation measure to be developed sometime in the future violates CEQA, which only allows agencies to defer formulation of specific mitigation measures if the agency "articulate[s] specific performance criteria and make[s] further approvals contingent on finding a way to meet them."[127]

In its Response to Comments, the County attempts—but fails—to defend MM 4.3-8's unlawful lack of performance standards.

The County asserts it may rely on existing state law requirements: specifically, a purported requirement in "Public Resources Code § 74641, subdivision (c)" for CCS projects to adopt an air quality monitoring and mitigation plan.[128] The County's citation is erroneous, as no such section of the Public Resources Code exists.

Presumably, the Final REIR intended to cite Public Resources Code section 71464(c), which provides that all CCS project operators "shall . . . [c]reate an air monitoring and mitigation plan to measure, track, and minimize potential toxic air contaminants and criteria air pollutants from the site of the carbon dioxide capture, removal, or sequestration project and submit the plan to the state board."

In any event, although there may be circumstances when an agency can rely on other regulatory requirements, pointing to Public Resources Code section 71464(c) is unavailing here because it does not supply performance criteria. Like MM 4.3-8, it does nothing more than require the creation of a plan. Crucially, nothing in section 71464(c) or MM 4.3-8 reflects a "commit[ment] . . . to specific performance criteria for evaluating the efficacy of the measures implemented."[129]

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[126] RDEIR, Vol. 1 at 1-31 to 1-32, 4.3-74.
[127] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 856, quoting *Endangered Habitats League, Inc. v. County of Orange* (2005) 131 Cal.App.4th 777, 793.
[128] Final REIR, Vol. 3, Response GR-6e at 7-58
[129] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 856.

Although section 71464 does state that the purpose of the monitoring and mitigation plan is "to measure, track, and minimize potential toxic air contaminants and criteria air pollutants,"[130] this is not sufficient to meet CEQA's requirements. In assessing CEQA compliance, courts recognize a "distinction between stating a generalized goal and adopting specific performance criteria. 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."[131]

According to the County, MM 4.3-8 reflects performance criteria because it "requires the owner/operator to work with the SJVAPCD and [California Air Resources Board (CARB)] to develop a monitoring plan that meets specified regulatory standards for the UIC permit."[132] But a mere requirement for the Project to "work with" the Air District and CARB does not satisfy CEQA, which requires identification of "specific performance standards."[133]

Moreover, it is unclear what the County means when it suggests the fence line monitoring plan for air emissions must meet "specified regulatory standards for the UIC permit."[134] To the extent there are specific regulatory standards that apply to a fence line monitoring program for criteria and toxic air pollutants emitted from CCS facilities, the Final REIR needed to identify those standards—both to inform the public and decisionmakers and to make certain that the Project's mitigation obligations are explicitly stated and fully enforceable. The Final REIR pointedly does not identify any such "specified regulatory standards," and Commenters are not aware of any such standards that would address "all air constituents generated by the CCS project including but not limited to: criteria pollutants, CO_2, and H_2S,"[135] as contemplated by MM 4.3-8.

Finally, the County asserts that, for MM 4.3-8, "the performance standards and commitments are contained in the EPA appendices and regulatory requirements, which must be complied with as provided in the mitigation measures."[136] This assertion that the details of the fence line monitoring plan for air emissions will be dictated by EPA does not align with the text of MM 4.3-8, which does not require EPA to approve the plan—just the local Air District and CARB.[137] Under MM 4.3-8, the Project need only provide a copy to EPA.[138] But even if EPA was required to approve the fence line monitoring plan for air pollutant emissions, to the extent the County intends to cross-reference and impose existing regulatory requirements as mitigation for the Project, the Final REIR needed to identify those standards to inform the public and decisionmakers and to make certain that the Project's mitigation obligations are explicitly stated and fully enforceable.

[130] Pub. Resources Code, § 71464(c).
[131] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 856.
[132] Final REIR, Vol. 3, Response GR-6e at 7-59.
[133] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 860.
[134] Final REIR, Vol. 3, Response GR-6e at 7-59.
[135] RDEIR, Vol. 1 at 1-31 to 1-32, 4.3-74.
[136] Final REIR, Vol. 3, Response GR-6e at 7-59.
[137] RDEIR, Vol. 1 at 1-31 to 1-32, 4.3-74.
[138] RDEIR, Vol. 1 at 1-31 to 1-32, 4.3-74.

Rather than persist in unlawfully deferred mitigation, 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 fence line, 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.

Additionally, to better protect community members, parameters for the fence line monitoring plan contemplated by 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 project fence line), the number of monitors, and the thresholds that will trigger community notification and response requirements.

6. The Final REIR fails to adopt all feasible mitigation to address Valley Fever.

The Final REIR institutes one mitigation measure, MM 4.3-7, to address Valley Fever.[139] MM 4.3-7 is inadequate and does not incorporate all feasible mitigation to address Valley Fever.

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

As Commenters explained previously, 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 Final REIR for that project.[140]

In its Response to Comments, the County rejects this suggestion on the grounds that the Draft EIR for the 99 Houghton Industrial Park project "was never considered at a public hearing and never certified."[141] This is non-responsive, as feasibility is the litmus test for mitigation under CEQA, and all feasible mitigation must be adopted.[142] The County avers that the measures for 99 Houghton Industrial Park are not feasible because that project "would involve extensive grading of the entire site" whereas this Project only requires grading for "the limited pipeline width and injection well sites."[143] But the County does not explain how the size of the area to be graded renders the additional mitigation measures infeasible. Indeed, many of the following measures would seem to be easier and cheaper to implement at a smaller site:

- 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.

Consequently, the County must adopt these additional, feasible mitigation measures to protect workers and prevent illness from Valley Fever.

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[140] See RDEIR Comments at 40; Kern County Planning & Nat. Resources Dept., *Recirculated Draft Environmental Impact Report for 99 Houghton Industrial Park Project* (Oct. 2019) at 4.3-48 to 4.3-49, https://psbweb.kerncounty.com/UtilityPages/Planning/EIRS/99_Houghton/DEIR/_99_Houghton_RDEIR_Vol%201.pdf.
[141] Final REIR, Vol. 3, Response 3-064 at 7-129.
[142] Pub. Resources Code, § 21002; CEQA Guidelines, § 15126.4(a)(1).
[143] Final REIR, Vol. 3, Response 3-064 at 7-129.

7. The Final REIR fails to adopt all feasible mitigation for cumulatively significant net increases in nonattainment air pollutants, including $PM_{2.5}$.

To address the CTV I Project's significant criteria air pollutant emissions, the Final REIR includes MM 4.3-5, which "requires the execution of a Developer Mitigation Agreement (DMA)" with the Air District.[144] According to the Final REIR: "[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."[145]

As Commenters noted previously, MM 4.3-5 fails to meet CEQA's requirements in several respects:

- 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, but the Measure fails to specify that the agreement must be approved by the County as well, subject to public review and comment.

- Not only should MM 4.3-5 be amended to require County approval of the DMA, it should specify that the County will withhold its approval unless and until 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 "shall be reviewed by the California Air Resources Board for compliance with" section 39741.1 "before execution and adoption,"[146] 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.

- 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 Final REIR should be revised to clarify what the terms in the mitigation measure mean.

- To the extent the County intends to treat all the criteria air pollutants interchangeably for purposes of mitigation, it should reconsider, as such an approach fails to ensure that significant increases in particular air pollutants will

[144] RDEIR, Vol. 1 at 4.3-70.
[145] RDEIR, Vol. 1 at 4.3-68.
[146] RDEIR, Vol. 1 at 4.3-71.

be reduced, as CEQA requires. In this regard, the conflation of $PM_{2.5}$ and PM_{10} is especially problematic.

- To ensure the measure is enforceable and effective, 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 Final REIR'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 Final REIR's estimates and/or the initial fee proves to be insufficient.

As Commenters noted previously, 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, although it appears the County intends to weaken the measure. Previously, the County indicated that MM 4.3-5 would require monies collected pursuant to the DMA to be used to fund pollution-reducing mitigation projects within a 20-mile radius.[147] Although nowhere acknowledged in the Final REIR, County staff have recommended that MM 4.3-5 be amended to allow funds to be spent anywhere "in the valley portion of Kern County within the San Joaquin Air District boundary designated as disadvantaged communities."[148] Although a requirement to spend DMA funds on disadvantaged communities within Kern County is better than no requirement at all, the best use of the money would be to fund pollution-reducing projects in the communities nearest to, and therefore most affected by, the Project. To that end, if the County is unwilling to set a strict distance limitation for funding eligibility, it should at least amend MM 4.3-5 to specify that disadvantaged communities closest to the Project will be prioritized for funding.

MM 4.3-5 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."[149] As Commenters noted previously, this 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 4.3-5 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.

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[147] RDEIR, Vol. 1 at 4.3-71.
[148] Staff Report at 38.
[149] RDEIR, Vol. 1 at 4.3-71.

- 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 Final REIR's Analysis and Mitigation of Climate Impacts is Inadequate.

The Final REIR's GHG emissions analysis is unsupported, self-contradicting, and violates CEQA's requirements for proper analysis. The document does not acknowledge or correct the flaws in the Recirculated Draft EIR.

First, the Final REIR's GHG analysis is still plainly inadequate, as it relies on contradictory and false premises, and lacks disclosure or analysis of crucial information. The document purports to analyze GHG impacts from future CO_2 sources it also argues are impossible to analyze. Moreover, it claims that these sources will be "hard to decarbonize" while this claim is contradicted by the Final REIR'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. And the analysis of CO_2 retention in the ground is still not supported by the evidence, as the attached October 16, 2024 DiGiulio Report shows. The analysis ignores crucial leakage risk factors that contradict the claim that CO_2 will remain permanently in the ground, relies on under-protective and unrealistic assumptions, and fails to provide the required information to support its conclusions.

Second, the GHG analysis doubles down on the key contradiction Commenters already noted in comments on the Recirculated Draft EIR: the Final REIR'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 Final REIR 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. While no meaningful analysis or evidence supports any of these conclusions in the Final REIR, rendering the conclusions unsupported by substantial evidence, if they are accurate, they call the Project's entire premise into question.

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 Final REIR'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 Final REIR'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 Final REIR's GHG analysis is inadequate under CEQA.

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

The Final REIR still fails to correct one of the basic flaws at the heart of the GHG analysis: The analysis purports to present data that, according to the same analysis, does not exist. As shown in the RDEIR Comments, Table 4.8-6 presents "Projected Injection 2026-2045" to account for CO_2 injected from many sources beyond the initial sources the Final REIR describes and analyzes—the Elk Hills field gas streams.[150] At the same time, the Final REIR consistently avoids analyzing the impacts of these sources, arguing that information cannot be provided because "they have not been permitted or completed CEQA."[151]

The County does not dispute these facts but argues instead that the RDEIR Comments "fundamentally misunderstand the nature of the data presented."[152] The County repeats the argument that the proposed Project is "not designed, sized, or constructed to accommodate any future sources of CO_2."[153] The County again explains that none of the industries or projects identified in the Final REIR have been approved and each will require its own approval process.

Therefore, the County argues:

> estimated GHG emissions in Tables 4.8-4 through 4.8-6 are not intended as exact projections. Rather, the GHG emissions and sequestration figures are good-faith estimates based on maximum reservoir capacity that account for (1) the only known CO_2 source for the project and its operational details, whose uncertainties have been acknowledged by the RDEIR, and (2) the possibility that other sources of CO_2 might, at unknown points in the future, be permitted through separate approval and environmental review processes to sequester CO_2 within the existing natural reservoir underlying the project site.[154]

As already shown above in Section I.A of these comments, the County's claim that the Project is "not designed, sized, or constructed" to accommodate other sources but the initial sources is evidently not true. What the County presents as "good faith estimates" of injection at "unknown

[150] RDEIR, Vol. 1 at 4.8-26.
[151] RDEIR, Vol. 1 at 4.8-25.
[152] Final REIR, Vol. 3, Response GR-5e at 7-41.
[153] Final REIR, Vol. 3, Response GR-5e at 7-41.
[154] Final REIR, Vol. 3, Response GR-5e at 7-42.

points in the future" is presented with precision both in terms of injection volumes and in terms of timeframe, while at the same time the County argues it cannot provide any information about future sources. At the same time, the County refuses to conduct any analysis of the future sources' impacts. The County cannot have it both ways.

b. The GHG analysis relies on a false premise.

As pointed out in the RDEIR Comments, the Final REIR relies on the premise that CO_2 will come from "industries that are essential but hard to decarbonize." This premise is contradicted by the long list of allowed future sources that include many sources that cannot reasonably be characterized as hard to decarbonize.

In the Response to Comments, the County admits that the term "hard to decarbonize" does not apply to many of the CO_2 sources, including fossil fuels, and explains it actually "refers to production of certain materials included in the list of potential future CO_2 sources, including steel and cement production."[155] The County also takes issue with how "industries" should be defined.[156]

But the County fails to respond to or correct the main flaw in its analysis – the fact the GHG analysis *relies* on the premise it now admits is not true. The Final REIR states:

> The 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. In the larger global accounting of GHG the amount is not enough to address overall regional climate change but does support California's EO B-55-18 mandate to achieve carbon neutrality by 2045. Accounting for the GHG emissions reductions from CCS, the project's impacts related to GHG emissions would be less than significant.[157]

The Final REIR bases its finding that impacts would be less than significant, after accounting for emissions reduction from CCS, on the assumption CO_2 will come from hard to decarbonize industries. As this assumption is now evidently not true, the whole GHG analysis is unsupported and inadequate under CEQA.

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

Although the Final REIR 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),[158] the Final REIR's analysis goes only to the year 2045 and up to 31 MMT of CO_2.[159]

[155] Final REIR, Vol. 3, Response GR-1c at 7-22.
[156] Final REIR, Vol. 3, Response GR-1c at 7-22.
[157] RDEIR, Vol. 1 at 4.8-26.
[158] RDEIR, Vol. 1 at 4.2-14.
[159] RDEIR, Vol. 1 at 4.8-24.

The County admits in the Response to Comments that the Project could operate beyond 2045 for approximately 8 more years until injection reaches the maximum storage capacity,[160] but argues 2045 is a "conservative, reasonable projection" because 2045 is the year by which the state aims to phase out fossil fuel production, and the Elk Hills Power Plant may be forced to close.[161] This response is inadequate for two reasons. First, the County does not explain why this is a "conservative" projection. Analyzing only part of a project lifespan, by definition, avoids analyzing all potential impacts and is neither conservative nor reasonable. Second, this response assumes that the Project is wholly dependent on the Power Plant's continued operation, but the County does not provide any evidence that in 20 years alternative power sources will not be available to continue operations. The Final REIR failed to analyze the Project's *full* life span, as this is the "whole of the action" under CEQA.

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

The Final REIR still fails to address the critical question of whether the CTV I Project may extend the life of the Elk Hills Power Plant or of any other fossil fuel source, and the resulting GHG emissions implications. the County's response is inadequate because it focuses on the Elk Hills Power Plant only, ignoring the fact the Project contemplates sourcing CO_2 from both oil field gas streams and power plants.[162] The response dismisses our comment by stating "there is no evidence that the operational lifetime of facilities other than the Elk Hills oilfield and power plant will be extended by the existence of the proposed project." As shown in our comments, this is clearly a potential impact of the Project that should be addressed.

e. The GHG analysis does not disclose or analyze the impacts of potential offset credit generation.

In response to our comments arguing the Recirculated Draft EIR failed to disclose whether the CTV I Project can generate offset credits, the County argues that outside mechanisms, including CARB's oversight, will address the issue and prevent double counting.[163]

The County's response ignores its duty to analyze and mitigate potential impacts. As shown in the RDEIR Comments, and unlike the picture the County's response tries to paint, the issue of carbon accounting for CCS projects is highly complex and far from resolved. The Final REIR therefore needed to include the appropriate safeguards and measures and not rely on outside actors to avoid double counting, and to guarantee that its GHG impact analysis is supported by substantial evidence.

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

The Final REIR'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

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[160] Final REIR, Vol. 3, Response GR-5g at 7-42.
[161] Final REIR, Vol. 3, Response GR-5g at 7-43.
[162] RDEIR, Vol. 1 at 3-13.
[163] Final REIR, Vol. 3, Response GR-5h at 7-43 to 7-44.

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.[164] The Final REIR also 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."[165]

Thus, the analysis assumes that barring a leak "at injection" or "release due to unforeseen circumstances or equipment failure," the injected CO_2 will remain sequestered in the ground permanently. The County argues that the Final REIR relies on CARB's effectiveness metric for CO_2 retention in the ground, and that it provides substantial evidence to show this standard will be met.[166] However, as the July 18, 2024 DiGiulio Report and the October 16, 2024 DiGiulio Report show, this claim is not supported by the evidence, and is in fact contradicted by it. The full extent of the failure to support the Final REIR's analysis and conclusions with evidence is detailed in the DiGiulio reports, and below are a few examples.

First, the County argues that it is not required to rely on a permanence standard from scientific literature but nevertheless relies on CARB's permanence standard – a standard that was developed as part of the Low Carbon Fuel Standard (LCFS) program.[167] The problem with this standard is that it is not stringent enough to support the County's claim of retaining CO_2 in the ground, because it allows for significant emissions. In fact, the County's own consultant admits in their report that "[i]n evaluating the lifecycle carbon intensity for fuels, the LCFS uses a separate methodology and accounting system from the California Environmental Quality Act (CEQA), and so LCFS crediting is not comparable to the facility-level operational GHG emissions in the context of CEQA."[168] This, standing alone, is enough to suggest the use of the LCFS-based standard is not supported by substantial evidence and the County's use of that standard is not adequate under CEQA.

The CARB permanence standard fails in practice, not just in theory. As Dr. DiGiulio shows in his report dated October 16, 2024, the Project can have major leakage at wellbores and still attain the CARB permanence standard. Dr. DiGiulio finds that CARB's standards for carbon storage sites could allow for a far higher amount of CO_2 emissions when compared to emission rates allowed at legacy wells that are currently being plugged to control natural gas leakage in the state.[169]

It should be noted that CARB's standard was developed for LCFS purposes, that is, for a financial crediting program rather than for mitigation of impacts from CCS projects. And as Dr. DiGiulio notes, it is "not protective in regard to climate change mitigation – which is the stated

[164] RDEIR, Vol. 1 at 4.8-26.
[165] RDEIR, Vol. 1 at 4.8-26.
[166] Final REIR, Vol. 3 at 7-78.
[167] Final REIR, Vol. 3, Response GR-7g at 7-68.
[168] Final REIR, Vol. 3, App. A-3: Ramboll Technical Memorandum at 3.1.
[169] Oct. 16, 2024 DiGiulio Report at 21–22.

main purpose of this project – and is far less stringent than corrective measures being taken at wells that are required to be abandoned in California and elsewhere."[170]

Second, the County fails to show it will achieve even the weaker CARB standard, or any standard for CO_2 retention in the ground. The Final REIR's analysis ignores potential leakage from the hundreds of wellbores on the Project's site, rendering its analysis unsupported by the evidence. 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.[171] Given the large number of legacy wells in the area – over 300 well penetrations – a robust evaluation of wellbore integrity of both plugged and unplugged wells prior to injection is required to accurately assess CO_2 retention.[172] It is clear from the County's response that such an evaluation was not conducted and will not be conducted.

The County admits that it does not require mechanical integrity testing for all legacy wellbores and says the argument that such testing is necessary is "not correct."[173] The County argues that each existing wellbore within the Project's Area of Review was "individually evaluated to identify wellbores that must be plugged and abandoned prior to CO_2 injection to remove a conduit for leakage."[174] The County further argues that the Corrective Action Plans identified almost 200 wells in the Project site that "require pre-operational abandonment."[175]

But the County fails to address the fact that this "pre-operational abandonment" action does not guarantee the integrity of the legacy wells, and therefore does not address the potential leakage from these wells. A crucial element that must be known to assess CO_2 retention is the condition of the cement outside well casings, because if cement within the confining layer is compromised, CO_2 will migrate outside.[176] But the Final REIR fails to account for this factor.

As Dr. DiGiulio explains in his October 16, 2024 Report, under the EPA Class VI rules, injection wells need to go through mechanical integrity testing which includes a cement bond and variable density log (CBL/VDL) test. The CBL/VDL test evaluates cement quality outside well casing.[177] However, as the County admits, the CalGEM rules that apply to non-injection legacy well abandonment do not require conducting such integrity tests. For one reason, it is because these rules were not developed for the purpose of guaranteeing CO_2 retention in the ground in CCS projects.[178] The County therefore has a duty to conduct the required testing, and until it does, there is no support for the assumption that CO_2 will be retained permanently in the ground.

This lack of testing and thus lack of evidence alone renders the whole GHG analysis unsupported. But as the DiGiulio reports explain, this failure is exacerbated by several factors

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[170] Oct. 16, 2024 DiGiulio Report at 22.
[171] July 16, 2024 DiGiulio Report at 14.
[172] July 16, 2024 DiGiulio Report at 14.
[173] Final REIR, Vol. 3, Response GR-7h at 7-70.
[174] Final REIR, Vol. 3, Response GR-7h at 7-70.
[175] Final REIR, Vol. 3, Response GR-7h at 7-70.
[176] Oct. 16, 2024 DiGiulio Report at 20.
[177] Oct. 16, 2024 DiGiulio Report at 20.
[178] Oct. 16, 2024 DiGiulio Report at 30.

that make leakage from legacy wellbores even more likely and the lack of support for the analysis even more evident.

The County admits in its Response to Comments that there is no expectation that substantial mineralization of CO_2 will occur over the years of storage, and the Final REIR was revised to reflect that fact.[179] This further highlights the magnitude of the risk of leakage because, as Dr. DiGiulio explains, CO_2 in the Project will be stored in the least secure form: a highly pressurized supercritical fluid that "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."[180]

Another exacerbating fact is the density of legacy wells. 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.[181] 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 permanence scenario for geologic storage of CO_2.[182]

The last exacerbating factor is that a substantial number of wells in the 26R reservoir were completed prior to development of important cement standards and therefore present an even higher risk of leakage. Recommendations for cement compositions and well-plugging procedures were not established by the American Petroleum Institute until 1953. Hence, the quality of cement in wellbores that predate this year is highly questionable. This further exacerbates the leakage risk that stems from cement integrity the County fails to address.[183]

Third, the October 16, 2024 DiGiulio Report shows that the analysis is not supported by the evidence because it relies on flawed assumptions and lacking data. The assumptions used in the analysis simulations are unrealistic, under-protective, and fail to reflect the actual risk of leakage. The flawed assumptions are described in detail in the Report, and include unrealistic cement sheath permeability values, and a gross overestimation of the condition of cement in legacy wells, to name just a few.[184] Given all those deficiencies, Dr. DiGiulio finds the County's conclusion that the Project will meet CARB's CO_2 retention standards is not supported by the evidence.[185]

Fourth, the analysis is both internally contradictory and inconsistent with EPA's Class VI permits for the Project. First, as Dr. DiGiulio explains, the Recirculated Draft EIR found that no wells out of the existing 354 wellbores on the site require corrective action, which is at odds not just with the published rates of wellbore failure rates but also with the Final REIR's own evidence. The Blade Report found that cement sheaths were compromised at 3 of 31 wells that had CBL/VDLs that the County examined. This is not a 0 percent failure rate.[186] Second, as shown in the October 16, 2024 DiGiulio Report, out-of-zone migration, including to the

[179] Final REIR, Vol. 3, Response GR-7f at 7-67.
[180] Oct. 16, 2024 DiGiulio Report at 10
[181] July 16, 2024 DiGiulio Report at 9.
[182] July 16, 2024 DiGiulio Report at 9.
[183] Oct. 16, 2024 DiGiulio Report at 8, 25.
[184] Oct. 16, 2024 DiGiulio Report at 22–26.
[185] Oct. 16, 2024 DiGiulio Report at 26.
[186] Oct. 16, 2024 DiGiulio Report at 40–41.

Etchegoin Formation, would trigger corrective action from EPA under its Class VI permitting program. The DiGiulio Report also details a recent relevant incident in a CCS facility in Illinois that triggered a Notice of Violation (NOV) by the EPA. At the same time, "the County treats the Etchegoin Formation as an area where leaks may technically be allowed, even though this directly conflicts with what's allowed under the federal Class VI regulations."[187]

Fifth, the analysis fails to account for emergency venting. The Final REIR discusses venting CO_2 from surface facilities in the event of an emergency. There is no explanation of what the term "surface facilities" means and no discussion of how loss of CO_2 will be quantified during venting.[188]

Finally, the Final REIR's GHG analysis is not supported by the evidence because it fails to disclose information regarding wellbores that is essential for evaluation of CO_2 retention and the risk of leakage. Even though wellbore schematics are "absolutely vital" in understanding the need or potential need for corrective action,[189] CTV did not provide them, claiming them to be business confidential information. In its Response to Comments, the County argues that "Information for each well is available for public review via CalGEM well records such that providing this in the RDEIR does not further inform the environmental analysis."[190]

This answer violates the County's duty under CEQA to include "sufficient detail to enable those who did not participate in its preparation to understand and to consider meaningfully the issues the proposed project raises."[191] Instead of providing the information, the County is expecting the public to engage in a highly complicated and time-consuming mission to extract data the County already holds. Dr. DiGiulio, who is an expert on the issue, explains that it is "difficult if not impossible for a third party to generate well diagrams and review internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc. for 354 wellbores during a public comment period."[192] Moreover, it seems that the necessary data on cement bonds is available for only 31 wellbores out of the 354, leaving the public with no useful information to evaluate the potential GHG impacts.

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.

g. The GHG analysis claim of GHG capture rate is not supported by the evidence.

The Final REIR argues that it is "anticipated that this project would capture and inject approximately 101,743 tpy in Phase 1 and 101,743 tpy in Phase 2 of concentrated CO_2 (more

[187] Oct. 16, 2024 DiGiulio Report at 28.
[188] Oct. 16, 2024 DiGiulio Report at 30–31.
[189] Oct. 16, 2024 DiGiulio Report at 35–36.
[190] Final REIR, Vol. 3, App. A-4: Cornerstone Engineering, Inc. Technical Report in Support of Response to Public Comments (Cornerstone Report) at 11.
[191] *Sierra Club, supra*, 6 Cal.5th at 510.
[192] Oct. 16, 2024 DiGiulio Report at 36.

than 95 percent)."[193] Regarding a future blue hydrogen source, the REIR claims that "CCS capture efficiencies are expected to reach 85 to 95 percent, leaving 5 to 15 percent of the CO_2 to be emitted (IRENA 2020)." [194]

The claim regarding a carbon capture rate of 95 percent is not supported by the evidence and is in fact contradicted by it. Multiple studies have shown that CCS projects rarely achieve the level of capture they claim.[195] For blue hydrogen, an analysis found that no CCS project has captured more than 80% of its CO_2 emissions, with most capturing only one- to two-thirds of the CO_2 they produce.[196] The Final EIR fails to support its capture rate claim with evidence, as it is required to do.

h. *The Final REIR's halfhearted and contradictory finding of potentially significant GHG impacts violates CEQA.*

The Final REIR's conclusions and findings regarding the significance of GHG impacts are incoherent and internally contradictory. The County's Response to Comments on this issue is inadequate: In essence, the County doubles down on its flawed analysis and, except for a minor addition of language to the summary of impacts in Table 1.1, fails to address the flaws of the Final REIR's significance findings.

The County's response restates the rationale of its flawed significance findings, explaining that "taking into account the emission reductions from CCS, the project's impacts related to GHG emissions would be less than significant." However, the County continues, "this conclusion is contingent on injected CO_2 remaining in the geographically confined reservoirs in perpetuity without leakage from injection and capture activities." Because, despite all mitigation measures, "the possibility of a release from unforeseen circumstances and equipment failures or stops to injection from monitoring failures remains," the Project's GHG impacts remain significant and unavoidable.[197]

First, the response seems to miss the point of a CEQA significance finding. If the finding is that the Project will have a significant and unavoidable impact from GHG emissions, the agency must take that into account when deciding whether to approve the project. Here, as the Project's main objective and reason to exist is to sequester CO_2 in the ground, the finding of a significant impact on GHG emissions calls into question the entire rationale for the project. But despite the significant impact undermining the Project's own objective, the County still somehow finds that the Project would support California's EO B-55-18 mandate to achieve carbon neutrality by 2045.[198]

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[193] RDEIR, Vol. 1 at 3-17.
[194] RDEIR, Vol. 2, App. K.4: Source Identification Memo.
[195] See, e.g., IEEFA, *The Carbon Capture Crux*; IEEFA, *Carbon Capture and Storage*, https://ieefa.org/sites/default/files/2022-09/The%20Carbon%20Capture%20Crux.pdf (last updated Dec. 5, 2023); IEEFA, *CCS Hype and Hopes Sinking Fast*.
[196] IEEFA, *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution* (Sept. 23, 2023), https://ieefa.org/resources/blue-hydrogen-not-clean-not-low-carbon-not-solution.
[197] Final REIR, Vol. 3, Response GR-5a at 7-35 to 7-36.
[198] Staff Report, Exhibit B: Statement of Overriding Considerations at 5.

The second flaw, as explained in detail in our RDEIR Comments, is that the finding still fails to include a proper analysis of the nature, extent, or magnitude of the risk from GHG emissions. The courts are clear that "an 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."[199] But the County nevertheless excused itself from this duty under CEQA, and the findings are not supported by substantial evidence.[200] The County's analysis simply does not adequately or coherently disclose or analyze the nature and magnitude of the risks that underpin its finding of a significant impact on GHG emissions.

For example, regarding the risk from equipment failure and maintenance activities, the County argues that Appendix F of the Final REIR "recognizes that there is a possibility of fugitive emissions from surface equipment in the event of equipment failure and that CO_2 will occasionally need to be vented from surface equipment for operational maintenance," and that based on all of the available information, it concludes "there is a very low, but not zero, possibility of occurrence of such releases."[201] Again, this response fails to adequately quantify, describe, and assess the nature of the risk of leakage. As an example, and as discussed above, the analysis fails to account for emergency venting from the Project.

Regarding the risk of leakage from the storage reservoir, as discussed in detail above, the Final REIR fails to properly disclose and analyze potential leakage from the 354 well penetrations at the Project site. To properly describe the nature and magnitude of CO_2 leakage impact, the County must ensure that the proper integrity testing is conducted on all wellbores in the Area of Review. This was not done. As explained in the October 16, 2024 DiGiulio Report, apparently only 31 of 354 wellbores in the 26R and A1/A2 reservoirs had these tests decades ago, and the results are no longer representative and cannot provide proper analysis of the impact.[202]

The Final REIR also fails to properly disclose and describe the risk of a well blowout. In response to the DiGiulio Report, the County argues that the draft EPA UIC permits contain provisions to prevent well blowout.[203] As Dr. DiGiulio explains, while there are safeguards to prevent a blowout at *injection* wells, this is not the case at legacy wells. Moreover, blowouts occur in "properly" plugged wells.[204] Exacerbating the risk is the fact that over 40 wells in the 26R reservoir were completed prior to the development of the current standards of cement, and 10 of these wells are already plugged. The County fails to disclose and describe, much less quantify, this "very high" risk.[205]

Another crucial flaw in the Final REIR's significance impact finding is the failure to properly disclose and describe the impact of seismic risk on potential CO_2 leakage. The flaws in the Final REIR's seismic analysis are discussed in detail in our previous comments and in the DiGiulio reports. The effects of natural or induced seismicity are of particular concern at the

[199] *Cleveland Nat'l Forest Found. v. San Diego Assn. of Governments* (2017) 3 Cal.5th 497, 514.
[200] See, e.g., *Sierra Club, supra*, 6 Cal.5th 502 at 514.
[201] Final REIR, Vol. 3, Response GR-5b at 7-38.
[202] Oct. 16, 2024 DiGiulio Report at 40.
[203] Final REIR, Vol. 3, Response GR-7i at 7-71 to 7-72.
[204] Oct. 16, 2024 DiGiulio Report at 8.
[205] Oct. 16, 2024 DiGiulio Report at 8.

CTV I Project site due to its effect on wellbores, which can occur even after a well is permanently plugged and abandoned.

The October 16, 2024 DiGiulio Report shows that the Final REIR underestimated the seismic risk in the Project's area and ignores the fact that EPA and CalGEM regulations do not address damage to wellbores from seismic activity.[206] The Report explains that seismic activity can and has damaged wellbores, and that the Final REIR improperly fails to include a ground motion parameter that would trigger wellbore integrity evaluation. Without such a trigger, it is impossible to assess the damage to wellbores and the accompanying risk of leakage.[207] Moreover, the DiGiulio Report stresses that such damage may have already been done to wellbores that predate the 1952 earthquake at the Project site. The County's failure to conduct the proper testing for these wellbores' integrity exacerbates the risk of leakage.[208]

The Final REIR's GHG analysis failed to include an accurate, meaningful discussion of GHG impacts that is supported by the evidence, including quantitative analysis where appropriate and necessary, and this evidence-supported analysis failed to reflect a consistent conclusion as to the nature, magnitude, and significance of the impact, including analysis of risk and uncertainty.

i. The Final REIR's GHG consistency analysis is inadequate under CEQA.

The County's response to our RDEIR Comments pointing out the inadequacy of its Scoping Plan consistency analysis fails to correct the flaws in the analysis. The County argues it provides substantial evidence that the Project is consistent with the Scoping Plan, however, it still ignores the inconsistencies.

When discussing one of the inconsistencies pointed out by Commenters, the County also argues it only needs to show that "the project is broadly consistent with the 2022 Scoping Plan."[209] But this is not what CEQA mandates. Under CEQA, an EIR "shall discuss any inconsistencies between the proposed project and applicable general plans, specific plans, and regional plans."[210] The Final REIR still fails to do so.

2. The Final REIR fails to analyze and mitigate cumulatively considerable GHG emissions impacts.

The County's Response to Comments doubles down on its cumulative impacts assessment and argues that it provides a "good faith disclosure of the general nature of potential future CO_2 source projects."[211] It does not. The Final REIR's disclosure, analysis, and mitigation of cumulative GHG impacts remain inadequate.

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206 Oct. 16, 2024 DiGiulio Report at 64–67.
207 Oct. 16, 2024 DiGiulio Report at 62–63.
208 Oct. 16, 2024 DiGiulio Report at 62.
209 Final REIR, Vol. 3, Response GR-5d at 7-40.
210 CEQA Guidelines, § 15125(d).
211 Final REIR, Vol. 3, Response GR-5i at 7-45.

a. The Final REIR fails to adequately analyze cumulatively considerable impacts on GHGs.

The County argues that its cursory and short cumulative GHG impact analysis is adequate because "[t]here are no currently operational CCS projects in California, and therefore no CCS-dependent CO_2 sources such as blue hydrogen or direct air capture facilities, or other CO_2 source categories operating in conjunction with CCS, on which to base a more definitive analysis." The County argues that a more detailed analysis would require "engaging in speculation."[212]

The section on cumulative impact analysis below, incorporated by reference here, explains why the County is wrong about the rationale and the requirements of a cumulative impact analysis. Cumulative GHG impacts include cumulatively considerable GHG emissions from any and all projects, and not just CCS or "CCS-dependent" projects.

In addition, a lack of existing similar projects with which to compare project impacts does not absolve the County of the obligation under CEQA to fully analyze and mitigate potential impacts, nor does it prevent the County from analyzing cumulative impacts in a more robust way. For significant parts of the analysis, the County does not need to compare impacts with an existing carbon storage project; it only needs projects that are in the same category as the Project's *CO_2 sources*. Some of these sources are common and have existed at other facilities for a long time, such as power plants, oil field gas, and cement factories. Other types of projects, like blue hydrogen and alternative fuels, may be more novel, but they exist and the available information about their impacts can and must be used in a cumulative impact analysis. Specifically, as noted in the RDEIR Comments, the hydrogen and DAC projects were advanced enough to be considered by other agencies, and the CalCapture project will be sourcing CO_2 from an operating plant owned by the Project proponent.

Finally, the County explains that it includes a discussion of the oil and gas industry impacts because "[o]ilfield gas streams beyond the initial CO_2 source are the only identified potential future CO_2 source category for the proposed project […] as to which detailed information developed from prior CEQA reviews is available."[213] Regardless of the fact this is inaccurate, as explained above, the County's analysis of this issue still fails to disclose the Project's cumulative impacts. All the Final REIR does in the context of oil and gas field cumulative analysis is to provide a short overview of future oil and gas production, and state that "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."[214] The Final REIR fails to discuss the most relevant question in the GHG cumulative analysis context – whether the Project will extend the life of fossil fuel extraction and use in the region, exacerbating further their known GHG impacts.

Another aspect of the Project's cumulative impacts that the County fails to address is the health impacts of the oil and gas industry. A recent report by the California Oil & Gas Public Health Rulemaking Scientific Advisory Panel discussed the public health dimensions of

[212] Final REIR, Vol. 3, Response GR-5i at 7-45 to 7-46.
[213] Final REIR, Vol. 3, Response GR-5i at 7-46.
[214] RDEIR, Vol. 1 at 4.8-32.

upstream oil and gas development in California. The Final REIR improperly failed to discuss these health impacts and how they may be exacerbated by the Project.[215]

b. The Final REIR does not provide adequate mitigation for GHG impacts.

The GHG mitigation measures identified in the Final REIR still 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.[216] Any proposed mitigation must also provide assurance that such implementation will in fact occur.[217] The proposed measures fail on all counts, and the County's response fails to rectify the issues raised in the RDEIR Comments.

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

The County's response relies on a new report added to the Final REIR, which, according to the County, shows MM 4.8-1 is adequate. However, the issues raised in the RDEIR Comments remain unresolved.

First, the County argues that "requiring compliance with regulations is a common and reasonable mitigation measure" under CEQA.[218] But the County ignores the fact that the EPA Class VI UIC permits for the Project are issued under the Safe Drinking Water Act (SDWA) and focus on water quality, not on other risks and impacts associated with CO_2 leakage. As a result, they do not, and cannot, cover all relevant aspects of such leakage for CEQA purposes.[219]

Second, with regard to the comment that monitoring is insufficient to detect leakage from well penetrations, the County relies on the Cornerstone Report to show the proposed monitoring is sufficient.[220] But the October 16, 2024 DiGiulio Report points out that soil-gas monitoring is not included in the Final REIR and explains why it must be included, along with the use of eddy covariance towers.[221]

Third, the County failed to justify the use of only one monitoring well in the Etchegoin Formation and to address the related issues raised in our RDEIR Comments.[222]

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[215] Cal. Oil & Gas Public Health Rulemaking Scientific Advisory Panel, *Public Health Dimensions of Upstream Oil and Gas Development in California: Scientific Analysis and Synthesis to Inform Science-Policy Decision Making* (June 21, 2024).
[216] Pub. Resources Code, § 21081.6(b); CEQA Guidelines, §15126.4(a)(2).
[217] *Anderson First Coalition v. City of Anderson* (2005) 130 Cal.App.4th 1173, 1186–87.
[218] Final REIR, Vol. 3, Response GR-5j at 7-46.
[219] July 16, 2024 DiGiulio Report at 10–11.
[220] Final REIR, Vol. 3, Response GR-5j at 7-47.
[221] Oct. 16, 2024 DiGiulio Report at 29.
[222] July 16, 2024 DiGiulio Report at 44–45.

Fourth, the County argues that the requirement in MM 4.8-1 that the monitoring plan be submitted "prior to any injection of CO_2" "should reasonably be understood to mean before the first injection activities take place."[223] But the County fails to clarify that in the Final REIR. Moreover, it is still unclear whether the County intends that this plan will be only submitted once, before the initial source's first injection, or before each new source's injection activities. This measure is therefore still vague and unenforceable.

Finally, the County argues that the Class VI permits for the Project cover all necessary action "to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods."[224] The County admits, therefore, that unless leakage is into the USDW or is major enough to endanger public health, there are no corrective measures required for CO_2 leakage to the surface, even if it is a major one and may result in a significant GHG impact. The October 16, 2024 DiGiulio Report stresses that GHG leakage into the atmosphere is not covered by existing regulation:

> There is no leak detection and repair program in the UIC program for a Class VI facility. The Class VI permit is designed to prevent leakage into a USDW, not the atmosphere. There is no wording in the Class VI permit nor in the RDEIR that states that evidence of wellbore leakage (outside of injection wells) would trigger re-entry or re-abandonment. CARB and CalGEM also do not have regulatory requirements triggering re-entry or re-abandonment of wellbores in the event of leakage.[225]

Moreover, the DiGiulio Report explains that "[i]f leakage at or in the vicinity of wellbores is detected during geological storage of CO_2, there is no regulatory mechanism to determine a maximum acceptable rate of leakage that would necessitate corrective action."[226] Monitoring is meaningless if it comes with no standards that would trigger action.

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

Our RDEIR Comments on MM 4.8-6 argued it can be used to offset any GHG operational emissions "associated with" the Project's capture facility. The County's response argues Commenters read the measure too broadly.[227] The County argues:

> MM 4.8-6 applies by its terms only to GHG emissions in two categories: (a) those that fall outside the Cap-and-Trade program or other mandatory greenhouse gas emission reduction requirement and (b) additional emissions generated from sources providing CO2 for injection.[…] Contrary to commenters' claim, this

[223] Final REIR, Vol. 3, Response GR-5j at 7-48.
[224] Final REIR, Vol. 3, Response GR-5j at 7-48.
[225] Oct. 16, 2024 DiGiulio Report at 30.
[226] Oct. 16, 2024 DiGiulio Report at 21.
[227] Final REIR, Vol. 3, Response GR-5j at 7-49.

> mitigation measure could not be used to offset the emissions of the CO_2 that will be sequestered by the project.[228]

The County's explanation, however, is inconsistent with the Measure's own language, which the County has not corrected.

First, the inclusion of the first comma in the first sentence means that the qualifying statement about emissions "not covered by the Cap and-Trade program or other mandatory greenhouse gas emission reduction measures" appears to apply only to construction equipment, and not to all emissions. The measure reads: "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 . . . ."[229] The County is responsible for drafting a mitigation measure that is consistent with its own public explanation of the measure, and it has failed to do this. Moreover, the term "greenhouse gas emissions associated with the capture facility" is not qualified or defined in any meaningful way, leaving the issue raised in the RDEIR Comments unresolved and ambiguous. Since GHG sequestered in the reservoir is no longer covered by any program, and it is "associated with" the Project, it is possible the measure may be used to offset all sorts of leakage. This would undercut the rationale behind carbon sequestration.

iii. MM 4.8-6's reliance on offset credits is not supported by the evidence, and is ineffective, unenforceable, and impermissibly deferred mitigation.

The County argues that MM 4.8-6 is effective, and that it will achieve the relevant standards of offsets being real, permanent, additional, verifiable, and enforceable. This will be guaranteed, according to the County, "[b]y specifying that any offsets be obtained through the California Air Pollution Control Officers Association Exchange Registry or other third party reductions verified by the San Joaquin Valley Air Pollution Control District or through an Emission Reduction Agreement with the San Joaquin Valley Air Pollution Control District."[230]

In other words, the County argues that the identity of the verifying agency, rather than the content of the Measure, will guarantee its effectiveness and enforceability.

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[228] Final REIR, Vol. 3, Response GR-5j at 7-48 to 7-49.
[229] The mitigation measure, in full, reads 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. 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 (Kern County)." RDEIR, Vol. 1 at 4.8-27 to 4.8-28.
[230] Final REIR, Vol. 3, Response GR-5j at 7-49.

But the County's response does not point to any performance standards for these offsets, and the mitigation measure includes no requirement that they will be real, permanent, additional, verifiable, and enforceable.

MM 4.8-6 allows credits by unidentified "third parties." The only check on effectiveness 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.[231] As explained in our RDEIR Comments, 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. CEQA only allows deferral if the agency "articulate[s] specific performance criteria and make[s] further approvals contingent on finding a way to meet them."[232]

Courts have found GHG measures to be unlawfully deferred when, just like here, the deferral provided "only a generalized goal of no increase or net zero GHG emissions, and then allows the Director to determine whether any particular offset program is acceptable based on unidentified and subjective criteria.".[233]

Moreover, the reliance on SJVAPCD to verify credits ignores the evidence of its past failure to properly verify emission credits under its Emission Reduction Credit (ERC) Program. A June 2020 report by CARB found that under the ERC program, credits were overvalued and issued under circumstances that do not meet legal requirements.[234] The Final REIR fails to provide evidence that the systematic issues raised in the CARB report were addressed and do not still pervade SJVAPCD's crediting programs.

The second part of MM 4.8-6 pertains to the CO_2-sending sources and requires they "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."[235] As described in our RDEIR Comments, this part of the Measure suffers from the same fundamental flaws as the first part, namely that mitigation is deferred without any performance standards to guarantee its effectiveness. In addition, it fails to specify to whom such "certification" would be provided, making it entirely unenforceable and ineffective. The County failed to respond to or correct these flaws.

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[231] *King & Gardiner Farms*, *supra*, 45 Cal.App.5th at 856.
[232] *Id.*, quoting *Endangered Habitats League*, *supra*, 131 Cal.App.4th at 793.
[233] *Golden Door Properties, LLC v. Cnty. of San Diego* (2020) 50 Cal. App. 5th 467, 519–20.
[234] CARB Enforcement Division, *Review of the San Joaquin Valley Air Pollution Control District Emission Reduction Credit System* (June 2020), https://ww2.arb.ca.gov/sites/default/files/2020-06/SJV_ERC_FINAL_20200604.pdf (CARB Audit Report).
[235] RDEIR, Vol. 1 at 4.8-28.

iv. 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.

In response to the RDEIR Comments on MM 4.8-2 through MM 4.8-5, the County argues that "[m]itigation is not deferred because performance standards and commitments are contained in the EPA appendices and regulatory requirements, which must be complied with as provided in the mitigation measures."[236]

This response ignores the other issues raised in the RDEIR Comments, including the fact that the standards relied on by the measures were not developed for GHG mitigation and the measures fail to add any standards or measures to mitigate potential impacts from GHG emissions.

v. The Final REIR fails to adopt all feasible mitigation to mitigate GHG impacts

The Final REIR fails to adopt all feasible mitigation to mitigate GHG impacts. In addition to the deficiencies noted above, the final REIR should have been revised to include additional measures that will mitigate GHG impacts from the Project, in particular impacts from CO_2 leakage.

First, the County must specify the conditions that will trigger corrective action in case of leakage. As the October 16, 2024 DiGiulio Report explains, "[t]here is no wording in the Class VI permit nor in the RDEIR that states that evidence of wellbore leakage (outside of injection wells) would trigger re-entry or re-abandonment. CARB and CalGEM also do not have regulatory requirements triggering re-entry or re-abandonment of wellbores in the event of leakage."[237] These condition should include, but are not limited to, a maximum allowable CO_2 emission rate at a wellbore that will trigger corrective action.[238]

Second, the Final REIR improperly failed to require internal mechanical integrity testing prior to plugging non-injection wells. As explained in the DiGiulio Report, because all wellbores penetrating the confining layer will be in direct contact with supercritical CO_2 at high pressure, all wellbores should be subjected to the proper testing prior to plugging.[239] At a minimum, the County should add a measure requiring CTV to work with CalGEM to conduct CBL/VDLs in wellbores prior to plugging.[240]

Finally, the Final REIR improperly failed to include further mitigation measures to address seismicity impacts: in particular, it should have required that if induced seismicity having a magnitude of **M** 2.7 or larger occurs, the operator will conduct an evaluation of the integrity of <u>all</u> wellbores including those plugged and abandoned.[241]

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[236] Final REIR, Vol. 3, Response GR-5j at 7-50.
[237] Oct. 16, 2024 DiGiulio Report at 30.
[238] Oct. 16, 2024 DiGiulio Report at 21–22.
[239] Oct. 16, 2024 DiGiulio Report at 37–38
[240] Oct. 16, 2024 DiGiulio Report at 20.
[241] Oct. 16, 2024 DiGiulio Report at 32–33.

C. The Final REIR's Analysis and Mitigation of Energy Use Impacts is Inadequate.

The Final REIR still fails to adequately disclose, analyze, and mitigate the CTV I Project's impacts to energy resources.

Response to Comment 3-105 claims that "[c]arbon capture and sequestration projects, such as the proposed project, are essential to achieve the State's climate goals (CARB 2022); as a result, any energy consumed by the project is not considered to be wasteful or unnecessary."[242] This statement lacks substantial evidence to support it. And Response to Comment 3-107 states that "[a]s for reducing the reliance on fossil fuels, while [sic] that is a California policy is not a Kern County policy and therefore the project does not have to comply with as [sic] such requirement for consideration of the Conditional Use Permit."[243] But CEQA Guidelines Appendix F, the source of the goal of reducing reliance on fossil fuels, is applicable to all projects statewide, by its terms—including projects where the lead agency is a local government. The statement to the contrary by the County is affirmatively misleading and contributes to the informational and analytical inadequacy of the EIR. Finally, the allegation that no *new* fossil fuel power plant will be necessary to power the Project does not lead to the conclusion that there are no impacts on energy consumption.

D. The Final REIR's Analysis and Mitigation of Geologic Risks is Inadequate.

It is essential that the Final REIR accurately analyze and adopt all feasible mitigation for geologic impacts because the significant risk of CO_2 leaks and the seismically active setting for the CTV I Project threaten the health and welfare of every Kern County resident as well as the entire premise of this Project. Geologic impacts are of concern because the Elk Hills field is littered with existing wellbores that can serve as leakage pathways, all in the state's highest seismic hazard zone.

As set forth in our DEIR Comments and RDEIR Comments, and the accompanying expert reports of Dr. DiGiulio, the original Draft EIR and the Recirculated Draft EIR both failed to adequately analyze or mitigate geologic impacts from the Project. Unfortunately, the County's Final REIR and Response to Comments do not remedy these deficiencies, as discussed below and in the additional attached expert report of Dr. DiGiulio dated October 16, 2024.

It should be noted at the outset that the County states throughout the Final REIR and in its discussion of geologic impacts in particular that it cannot consider certain impacts like cumulative impacts from the Project because "the state has no experience yet with multiple CCS projects in the same county" and therefore "validation from real world projects is unavailable."[244] However, the lack of other examples does not absolve the County of its obligation under CEQA to fully analyze and mitigate potential impacts, and further highlights why it is especially critical the County conduct a proper review before this Project can move forward – the CTV I Project is the first of its kind in California and presents serious risks to

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[242] Final REIR, Vol. 3, Response 3-105 at 7-135 to 7-136.
[243] Final REIR, Vol. 3, Response 3-107 at 7-136.
[244] See, e.g., Final REIR, Vol. 3, Response GR-7e at 7-67, Response GR-10b at 7-92.

nearby communities and the region as a whole that merit careful review. The novel nature of the Project does not excuse the County under CEQA from specifying important details and studying issues like geologic impacts.

1. The County still has not addressed the significant risk of leaks, blowouts, and seismic hazards in the Project area.

The October 16, 2024 DiGiulio Report discusses the numerous deficiencies in the County's Response to Comments and its new reports including the Cornerstone Technical Report. Due to these deficiencies, the Final REIR's geologic impacts analysis and significance findings do not meet the minimum requirements of CEQA, are unsupported and inadequate, and the discussion is not informationally adequate, supported by substantial evidence, or analytically sound.

Section V.B of these comments highlight some of the key issues discussed in the DiGiulio Report that are also relevant and incorporated by reference here. Critically, the County's Response to Comments still fails to address or acknowledge the continued risk that injected CO_2 will not remain permanently in the storage reservoirs. By relying on CARB's permanence standard under the LCFS Protocol, the County is employing a weak standard that likely is not stringent enough to ensure retention of CO_2 in the ground.[245] Worse, the County still cannot establish it meets even this weaker standard due in part to the significant risk of leaks via the high number of wellbores at Elk Hills – which "represents a worst-case scenario for permanence for geologic storage of CO_2."[246] The County instead largely dismisses this risk.[247]

The October 16, 2024 DiGiulio Report undermines several other key assumptions in the County's response. For example, the County's assumption that "maintain[ing] reservoir pressure at or below the discovery pressure" of the reservoirs will fully prevent leaks is inappropriate because those discovery pressures "are still high."[248] Additional flawed assumptions include unrealistic cement sheath permeability values and a gross overestimation of the condition of cement in legacy wells, among others.[249]

The County also continues to wave away the impacts of natural and induced seismicity in this region, despite the significant body of studies, research, and data submitted by Commenters, Dr. DiGiulio, and the public. For example, the County responds that "[e]vidence supports the conclusion that there is no significant risk of seismicity from pressure transmission below the Monterey Formation."[250] According to Dr. DiGiulio, however, the County's dismissal and

[245] Oct. 16, 2024 DiGiulio Report at 20–22.
[246] Oct. 16, 2024 DiGiulio Report at 19.
[247] See Final REIR, Vol. 3, Response GR-7b at 7-61 (County stating there have been "no instances of leakage through existing well bores during injection.").
[248] Oct. 16, 2024 DiGiulio Report at 10.
[249] Oct. 16, 2024 DiGiulio Report at 21–26.
[250] Final REIR, Vol. 3, Response GR-7e at 7-65.

"attempted quantification of induced seismicity of less than 1% at the Carbon TerraVault I facility is not substantiated" and "should be treated with considerable skepticism."[251]

In recent weeks, relevant new information has come to light that bears on the County's geologic impacts analysis and further calls into question this Project's premise and ability to safely store CO_2. Namely, a 5.2 earthquake near Bakersfield and a string of aftershocks over the past few months necessitate an updated seismic evaluation for the CTV I Project.[252] The Final REIR should have included this information to provide an accurate sense of the scale of the harm from nearby seismicity, rather than continue to minimize or ignore Commenters' concerns regarding the extent of natural seismicity in the Project area.

In addition, recent reports of a major leak at a monitoring well associated with the first CO_2 injection well permitted in the U.S., in violation of EPA's Class VI regulations, highlight the very real leakage risks of CCS projects like CTV I that the County has failed to grapple with.[253] This real-world example is especially concerning because the leak occurred at one of the main monitoring points of scrutiny for the project, creating more worry that non-monitored wells will have leaks the operator and public never learn about, or learn too late to avoid serious impacts. As discussed by Dr. DiGiulio, the Notice of Violation EPA issued to the injector in that case bears on the County's analysis for this Project and demonstrates that it likely has a fundamental misunderstanding of allowable CO_2 migration under the Class VI regulations that renders its analysis flawed – contrary to the County's Response to Comments, any potential CO_2 migration into the Etchegoin Formation would require corrective action by EPA, and the County must properly account for that fact.[254]

Importantly, the County fails to properly address the risk to the public, and in particular to surrounding communities, from potential well leakage and blowout impacts on future development. Under impact 4.9-1, the Final REIR argues that a 4,000-foot setback from sensitive receptors for injection wells will mitigate CO_2 leakage hazards.[255] But as explained in the October 16, 2024 DiGiulio Report, leakage and blowout hazards are not limited to injection wells and have a high risk of occurrence in legacy wells too.[256] In the Response to Comments, the County argues that risk to the surrounding population from future development encroachment

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[251] Oct. 16, 2024 DiGiulio Report at 69 ("while keeping pressure in the 26R and A1-A2 below initial development pressure reduces the potential for induced seismicity, it does not eliminate the potential for inducted seismicity at the Carbon TerraVault I project").
[252] See, e.g., Klein, *Tuesday's Earthquake in Kern County Wasn't the First – and Likely Won't Be the Last, Experts Say*, KVPR (Aug. 8, 2024), https://www.kvpr.org/science/2024-08-08/tuesdays-earthquake-in-kern-county-wasnt-the-first-and-likely-wont-be-the-last-experts-say.
[253] See, e.g., Anchondo, *First US CO2 Injection Well Violates Permit — EPA*, Energywire (Sept. 13, 2024), https://subscriber.politicopro.com/article/eenews/2024/09/13/first-u-s-co2-injection-well-violates-permit-epa-00178914; Letter from Michael D. Harris, Director, Enforcement & Compliance Assurance Div., EPA Region 5, to Todd Davis, Plant Manager, Archer-Daniels-Midland Company, *Re: Notice of Violation of Safe Drinking Water Act at CCS#2 Well (IL-115-6A-0001) Injection Well in Decatur, Macon County, Illinois and Opportunity to Confer* (Aug. 14, 2024), https://subscriber.politicopro.com/eenews/f/eenews/?id=00000191-e799-d539-add7-e7db17e90000.
[254] Oct. 16, 2024 DiGiulio Report at 27–28.
[255] RDEIR, Vol. 1 at 4.9-53 to 4.9-54.
[256] Oct. 16, 2024 DiGiulio Report at 6–8.

is limited by Mitigation Measure 4.11-2, which restricts the CCS Surface Land Area to specific uses like agriculture and energy storage, and that no other measures are necessary.[257] This response does not disclose how close injection wells are to the Surface Land Area border, and ignores the fact that some legacy wells might be very close to the Surface Land Area border and thus very close to future development, including that of sensitive receptors. The County fails to address that risk.

Moreover, as explained in the DREIR Comments, the Project is close to a community already overburdened with high levels of pollution, unemployment, poverty and linguistic isolation. In response to this issue, the County argues that the population in the Project's census track is racially predominanlty white and has a higher mean household income than Kern County as a whole.[258] This is misleading, as the Project's census track spreads over 618 square miles. The County should consider the communities closest to the Project.

Below are further examples of deficiencies that are discussed in the October 16, 2024 DiGiulio Report that should have been addressed in the Final REIR, though this is not an exhaustive list:

- The County's modeling to simulate potential leaks via existing wells employs faulty assumptions that underestimate permeability and leakage.[259]

- The County's analysis and conclusions demonstrate several key inconsistencies with EPA's Class VI permit requirements for the Project.[260]

- The County's overall "lack of transparency" in withholding key information and details about the Project is "unjustified" and "erode[s] public confidence in this project."[261] For example, the County continues to withhold critical wellbore diagrams, which prevents a complete understanding of the Project and its potential impacts.

- "[T]he problem remains that CTV will not evaluate damage to subsurface equipment including wellbores for a major tectonic seismic event unrelated to injection of CO_2" which is "concerning" given the "near 20% probability of major ground shaking in the project area over the next 100 years (the time frame within CTV's responsibility or care)."[262]

In addition to the County's failure to grapple with our RDEIR Comments and the expert reports of Dr. DiGiulio, it has also failed to address comments from expert agencies like the U.S. Geological Survey (USGS). For example, the County did not respond to USGS's comments flagging the risks of this Project due to the large number of wellbores at Elk Hills that have not

[257] Final REIR, Vol. 3, Response GR-4d at 7-34.
[258] Final REIR, Vol. 3, Response GR-3c at 7-28.
[259] Oct. 16, 2024 DiGiulio Report at 21–25.
[260] See, e.g., Oct. 16, 2024 DiGiulio Report at 26–28.
[261] Oct. 16, 2024 DiGiulio Report at 36.
[262] Oct. 16, 2024 DiGiulio Report at 61–62.

been permanently plugged back to surface, including discrepancies in the County's number of wellbores that require plugging.[263]

2. The County still fails to adequately address cumulative geologic impacts.

The failures described above continue to taint the County's cumulative impact analysis and render it inadequate under CEQA. Section V.I below on the overall cumulative impacts analysis in the Final REIR, incorporated by reference here, also explains why the County is wrong about the rationale and the requirements of a cumulative impact analysis.

For example, the County continues to claim it cannot consider cumulative impacts from the Project because "the state has no experience yet with multiple CCS projects in the same county" and therefore "validation from real world projects is unavailable."[264] The County's Response to Comments also doubles down on the deficiencies in the Recirculated Draft EIR and refuses to conduct further analysis on the "significant and unavoidable" cumulative geologic impacts "due to the uncertainty of the implementation of multiple [CCS] projects and the ability to simultaneously cease injection during a[] [seismic] event."[265] However, as reiterated throughout these comments, the lack of other examples does not absolve the County of its obligation under CEQA to fully analyze and mitigate potential impacts, particularly for a significant and novel project like this one.

The Final REIR dismisses any cumulative geologic impacts analysis due to potential CTV I Project sources as well, by claiming the sources "are not known at this time and would be analyzed on a site-specific basis at the project level."[266] This is insufficient. This EIR is the appropriate place – indeed, maybe the only possible place – to analyze the impacts from the full scope of the CTV I Project under CEQA.

3. The County still fails to adopt all feasible mitigation to address geologic risks.

The County continues to set forth mitigation measures to address the geologic impacts of the CTV I Project that are wholly inadequate under CEQA. The October 16, 2024 DiGiulio Report details numerous deficiencies in the County's mitigation measures and why they must be addressed and proposes measures the County should consider to mitigate Project impacts. Due to

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[263] RDEIR, Vol. 2, App. 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). See also 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/ (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).
[264] See, e.g., Final REIR, Vol. 3, Response GR-7e at 7-67, Response GR-10b at 7-92 (The County states the "cumulative impact analysis is thus guided by the practicality that no such [currently operational CCS] projects are available for analysis.").
[265] Final REIR, Vol. 3, Response GR-10b at 7-92.
[266] Final REIR, Vol. 3, Response GR-10c at 7-99.

the analytical flaws identified in the DiGiulio Report, the Final REIR's mitigation measures for geologic impacts do not address our RDEIR Comments and remain vague, ineffective, unenforceable, and impermissibly deferred, in violation of CEQA.

For example, the County continues to point to compliance with other agencies' regulations like EPA, CalGEM, or CARB in lieu of its own analysis or mitigation of significant impacts.[267] This is disallowed under CEQA. Many of these other regulations and requirements also demonstrate gaps or deficiencies that the County seems to be unaware of. For example, CTV cannot comply with "applicable [CalGEM] regulations to any wells being abandoned as a result of the CCS project"[268] because CalGEM has not yet developed regulations applicable to CCS projects like this one.[269] And CalGEM itself has a long history of failing to properly plug and abandon wells. Its failure has led to a state crisis where thousands of old wells have not been cleaned up and a large portion are leaking due to lack of proper oversight by CalGEM.[270] As reiterated in the October 16, 2024 DiGiulio Report, for example, "EPA and CalGEM regulations do not address damage to wellbores as a result of seismic activity."[271]

In the case of CARB, the County assumes the LCFS CCS protocol will address and mitigate potential impacts, even though that protocol's purpose is entirely focused on the separate question of whether CTV I qualifies for LCFS credits. The County cannot generically rely on these other agencies' requirements without at least describing what those requirements are and how they would reduce the Project's geologic impacts to less than significant.

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[267] See, e.g., Final REIR, Vol. 3, Response GR-7d at 7-65 ("Mitigation Measure 4.7-1 requires implementation of all requirements of CARB's Carbon Capture, Removal, Utilization and Storage Program. In addition, the proposed project is required to follow the state's CCS protocol which includes this requirement for post-earthquake integrity testing."), Response 7j at 7-78 ("The Cornerstone Report provides an expert opinion that implementation of Class VI permit and state law requirements is sufficient to monitor for and detect any CO_2 leakage during and after injection. If previously plugged and abandoned legacy well bores within the Area of Review show evidence of leakage, then re-entry and re-abandonment consistent with CalGEM requirements would be triggered. . . . In addition, operating oil and gas fields throughout California are currently subject to leak detection and repair programs administered by regional air districts . . .").

[268] Final REIR, Vol. 3, Response GR-7j at 7-73.

[269] See Comments from CRC on Kern County Draft Notice of Preparation for Project to Cindi Hoover at Kern County Planning & Nat. Resources Dept. (Feb. 28, 2022) (noting CRC and County "uncertain at what point jurisdiction changes (at first injection?), and when abandoning does it revert back to CalGEM at any point to approve abandonment permit and final abandonment operations" and County noting "[w]e don't have a clear view of what CalGEM's role will [be] in additional permitting for CCS").

[270] See, e.g., K. Ferrar, *California Must Improve Its Management of Idle Wells*, FracTracker Alliance (May 2, 2024), https://www.fractracker.org/2024/05/california-must-improve-management-of-idle-wells/; Sierra Club, *$23 Billion Question: What Created California's Orphan and Idle Well Crisis?* (Dec. 2023), https://www.sierraclub.org/sites/default/files/2023-12/Idle%20Wells%20Report.pdf; J. Fassler, *How the Oil Industry Indefinitely Delays Cleaning Up Oil and Gas Wells in California*, DeSmog (Feb. 6, 2024), https://www.desmog.com/2024/02/06/wspa-cipa-oil-idle-wells-ab2729-california/; A. Cantu, *California Lets Companies Keep 'Dangerous' Oil Wells Unplugged Forever*, Capital & Main (Oct. 23, 2023), https://laist.com/news/climate-environment/california-lets-companies-keep-dangerous-oil-wells-unplugged-forever.

[271] Oct. 16, 2024 DiGiulio Report at 65.

In addition to addressing the deficiencies in the Final REIR's current mitigation measures for geologic impacts and strengthening its seismic monitoring and mitigation plan measures, the October 16, 2024 DiGiulio Report recommends numerous additional feasible mitigation measures that the County should adopt to address the CTV I Project's serious impacts. For example, Dr. DiGiulio urges the County to conduct new cement bond and variable density logs for wells prior to plugging to mitigate the risk of leaks via the large number of existing wells at the field.[272] The County should also establish monitoring outside the area of review of the storage reservoirs to properly detect potential CO_2 migration.[273]

E. The Final REIR's Analysis and Mitigation of CO_2 Pipeline Safety Hazards is Inadequate.

Our RDEIR Comments and attached expert report from Richard Kuprewicz identified significant failures in the Recirculated DEIR's assessment of the Project's pipeline safety impacts. The Final REIR fails to address the identified shortcomings, as discussed below and in the additional attached October 15, 2024 Kuprewicz Report.

Overall, the October 15, 2024 Kuprewicz Report concludes that the "County's responses to comments, including the Cornerstone Engineering Report ("Cornerstone"), contain, at best, many misleading statements, and at worst, outright false statements concerning CO_2 liquid transmission pipelines for this project."[274] The Final REIR ultimately "demonstrate[s] the County and project proponent's lack of understanding and adequate analysis regarding CO_2 transmission pipelines and represent[s] poor engineering practices for this project."[275]

1. The County still has not addressed pipeline safety hazards, including the risk of CO_2 pipeline ruptures.

Missing details about the nature of the CTV I Project's pipeline construction and operations continue to prevent understanding of the applicable regulations and safety jurisdiction of relevant agencies, and thus a complete analysis and appropriate mitigation.

Contrary to the Final REIR's conclusions, CO_2 leaks pose a direct hazard to nearby communities in Kern County. Exposure to high concentrations of CO_2 can lead to a number of health problems (Table 1), which can be exacerbated for vulnerable groups and individuals with pre-existing conditions such as asthma or cardiovascular disorders that are common in the San Joaquin Valley.[276] The amount of time exposed to high or even moderate concentrations of CO_2 can greatly increase the risk of loss of consciousness or death. "Differences in CO_2 concentration between different lethality levels and exposure times are relatively small;" in other words, a small increase in concentration and/or exposure time can significantly increase the risk of

[272] Oct. 16, 2024 DiGiulio Report at 19, 24–25.
[273] Oct. 16, 2024 DiGiulio Report at 14.
[274] Oct. 15, 2024 Kuprewicz Report at 1.
[275] Oct. 15, 2024 Kuprewicz Report at 1.
[276] P. Blackburn, *Is Your Goose Cooked? The Potential Health Impacts of CO2 Pipeline Ruptures*, Pipeline Fighters Club (Sept. 25, 2024), https://pipelinefighters.org/news/is-your-goose-cooked-the-potential-healthimpacts-of-co2-pipeline-ruptures/.

death.[277] "After the rupture of a large-diameter CO2 pipeline [as with CTV I's proposed 16-inch pipeline], CO_2 concentrations within approximately 1,000 feet or more of the rupture, depending on pipeline diameter and length, may rise to very dangerous levels in less than 5 minutes. Even a mile or more away, depending on pipeline diameter, wind direction, etc., CO_2 concentrations may rise to dangerous levels in less than 15 minutes."[278]

EPA Table B-1. Acute Health Effects of High Concentrations of Carbon Dioxide		
Carbon Dioxide Concentration (Percent)	**Time**	**Effects**
17 – 30%	Within 1 minute	Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death
>10 – 15%	1 minute to several minutes	Dizziness, drowsiness, severe muscle twitching, unconsciousness
7 – 10%	Few minutes	Unconsciousness, near unconsciousness
	1.5 minutes to 1 hour	Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing
6%	1 – 2 minutes	Hearing and visual disturbances
	≤ 16 minutes	Headache, dyspnea (shortness of breath)
	Several hours	Tremors
4 – 5%	Within a few minutes	Headache, dizziness, increased blood pressure, uncomfortable dyspnea (shortness of breath)
3%	1 hour	Mild headache, sweating, and dyspnea (shortness of breath) at rest
2%	Several hours	Headache, dyspnea (shortness of breath) upon mild exertion

Table 1 - Summary of health effects from exposure to high CO2 concentrations[279]

The Final REIR fails to grapple with recent CO_2 pipeline failures. For instance, in April 2024, "an estimated 2,548 barrels of carbon dioxide (CO_2) leaked from [an] Exxon pipeline" in Louisiana.[280] Below are further examples of deficiencies that are discussed in the October 15, 2024 Kuprewicz Report that should have been addressed in the Final REIR, though this is not an exhaustive list:

- The County continues to demonstrate that it does not understand current federal pipeline safety regulations, and its attempts to frame these regulations as adequate

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[277] See P. Harper, *Assessment of the Major Hazard Potential of Carbon Dioxide*, Health & Safety Exectuive (June 2011) at 3, https://www.hse.gov.uk/carboncapture/assets/docs/major-hazard-potential-carbondioxide.pdf.

[278] P. Blackburn, *Is Your Goose Cooked? The Potential Health Impacts of CO2 Pipeline Ruptures*. See also J. Abraham et al., *CFD Simulation Models And Diffusion Models For Predicting Carbon Dioxide Plumes Following Tank And Pipeline Ruptures—Laboratory Test And A Real-World Case Study*, 17 Energies 1079 (2024), https://www.mdpi.com/1996-1073/17/5/1079.

[279] EPA, App. B–Part I: *Acute Health Effects of Carbon Dioxide* (June 2015), https://www.epa.gov/sites/default/files/2015-06/documents/co2appendixb.pdf.

[280] N. Lakhani, *'Wake-up Call': Pipeline Leak Exposes Carbon Capture Safety Gaps, Advocates Say*, The Guardian (Apr. 19, 2024), https://www.theguardian.com/us-news/2024/apr/19/exxon-pipeline-leak-carboncapture-safety-gaps.

and applicable to this Project "are misleading and inaccurate."[281] Contrary to the Final REIR, Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations ultimately may not apply to the CTV I Project.[282] Moreover, the County cannot backtrack on these attempts by now summarily noting that any pipelines "not under the authority of PHMSA shall be reviewed and approved for all safety features by the Kern County Fire Marshall."[283] The Fire Marshall is not a pipeline expert or regulating body. The County cannot rely on PHMSA regulations or the Fire Marshall to avoid its own CEQA analysis and mitigation.

- The County demonstrates it does not understand liquid transmission pipeline rupture dynamics and mainline valve effectiveness, which infects its whole pipeline safety analysis.[284]

- The County's claim that the maximum dispersion area in the case of a pipeline-related carbon leak at CTV I is 867 feet is "recklessly low"[285] and not based on substantial evidence given the 16-inch diameter CO_2 pipeline proposed for CTV I.

- The County's dispersion modeling seems to entirely ignore important conditions like local topography and wind patterns, omissions that lead to "incomplete and poor modeling"[286] and call the Project's analysis and mitigation into question. The County also fails to explain why it did not employ computational fluid dynamic modeling for CTV I,[287] which can better capture terrain impacts, particularly at an early enough stage where the company has "time to collect data, evaluate assumptions, and integrate a model's predictions into routing and emergency planning decisions,"[288] rather than dispersion modeling.

- The County also does not understand—and therefore does not address—the differences in the phases of CO_2 and their impact on this Project, particularly the important distinction of supercritical v. liquid state. While the Final REIR claims that the carbon will be in supercritical phase during pipeline transport, the 80 degrees Fahrenheit noted for the pipeline makes that impossible – at that temperature, the carbon would be in liquid phase,[289] which involves a different set of requirements and safety regulatory jurisdiction than claimed in the Final REIR, as well as a host of different potential impacts and required mitigation.

[281] Oct. 15, 2024 Kuprewicz Report at 2.
[282] Oct. 15, 2024 Kuprewicz Report at 2–3.
[283] Staff Report at 39.
[284] Oct. 15, 2024 Kuprewicz Report at 3.
[285] Oct. 15, 2024 Kuprewicz Report at 4.
[286] Oct. 15, 2024 Kuprewicz Report at 4.
[287] Oct. 15, 2024 Kuprewicz Report at 4.
[288] P. Blackburn, *A Tale of Perfect Goose Eggs: CO_2 Plume Computer Modeling Options*, Pipeline Fighters Hub (Sept. 30, 2024), https://pipelinefighters.org/news/a-tale-of-perfect-goose-eggs-co2-plume-computer-modelingoptions/.
[289] Oct. 15, 2024 Kuprewicz Report at 2.

- The County continues to downplay the Satartia, MS pipeline disaster. Although the Final REIR is correct that no one actually died in the incident, the leak nearly killed nearby residents and first responders.[290] The County's failure to grapple with this incident and develop appropriate best practice mitigation for this Project undermines the County's analysis of pipeline risks. Contrary to the County's claims, Elk Hills also presents unique pipeline-related risks to the local environment and nearby communities like Buttonwillow and McKittrick, particularly given the likely much larger dispersion area than the County assumes.

2. The County still fails to adopt all feasible mitigation to address pipeline safety hazards.

The County's flawed analysis infects its pipeline safety-related mitigation measures and renders them similarly deficient under CEQA. The few limited measures the County proposes are also vague, ineffective, unenforceable, and impermissibly deferred, in violation of CEQA.

For example, the Final REIR's mitigation measure providing a 4,000 ft. setback from the Project's injection wells—but not from its pipelines—followed by the County's later announcement that it would adopt a 1,367 ft. setback for Project pipelines from any property line outside the Project area, demonstrates arbitrary and capricious decisionmaking.[291] While 1,367 ft. is a welcome improvement from the County's initial proposal for a 50 ft. pipeline setback,[292] given the analysis in the Kuprewicz Report demonstrating that the County's assumed dispersion area of 867 feet is likely flawed, the County must adopt a larger setback for Project pipelines and show its work so the public has an opportunity to review and comment on its decisionmaking.[293]

In addition, the County's reliance on the ReadyKern emergency notification system as part of its mitigation requirement for an emergency response plan is unsupported. There are numerous flaws with ReadyKern and its parent company, Everbridge, that make this proposed mitigation measure to protect residents and workers tenuous at best. Further, there are unanswered questions about how ReadyKern would be deployed that the County must answer and resolve.

According to the Staff Report, the County added to its mitigations "encouragement of surrounding parcel owners to register for ReadyKern."[294] For example, per Mitigation Measure 4.11-5, 60 days before commencing CO_2 injection, the applicant will provide "all owners (surface and mineral) within the CUP boundary and all property owners (surface and mineral) for legal parcels within 1,367 of the approved CUP boundary" via certified mail with "instructions on access and registration" for ReadyKern.[295]

[290] Oct. 15, 2024 Kuprewicz Report at 4.
[291] Staff Report at 38.
[292] Final REIR, Vol. 3, Response GR-4d at 7-34.
[293] Oct. 15, 2024 Kuprewicz Report at 5.
[294] Staff Report at 38–39.
[295] Staff Report at 40. See also MM 4.9-18. Staff Report at 39.

ReadyKern describes itself as an "emergency notification system that alerts residents & businesses about natural disasters and other crises."[296] It is an opt-in service, meaning "residents and business owners must register the voice and text communication devices where they wish to receive messages."[297]

Merely providing information to encourage the use of an opt-in messaging service is insufficient to keep workers and others safe from a potentially deadly CO_2 leak. Because it is opt-in (and not automatic, like Amber Alerts), individuals—including temporary workers—would not be made aware of a potentially deadly leak of CO_2 from the Project. Generally, opt-in emergency alert systems have been shown to catastrophically fail or otherwise fall short in an emergency. According to a 2022 article titled, "Emergency alerts were a problem long before the Marshall fire," opt-in rates tend to be low, and students, tourists and other part-time residents don not tend to sign up.[298] After the Paradise Fire in Napa County, a "grand jury called the opt-in alert system and process for the 2017 wildfires 'not sufficient, if they functioned at all.'"[299] Of the 94 Everbridge alerts Boulder County sent since the middle of 2020, 88 had confirmation rates below 50 percent, sometimes as low as 0 percent.[300] According to one article, "Boulder County could have opted to send a wireless emergency alert through the federal system without using the database in Everbridge."[301]

The County must reconsider use of this opt-in system, or else plan for how it will notify those who have not signed up but could be in the area of a CO_2 leak in an emergency. In revising this mitigation, the County must consider questions such as:

- How will CTV or the County follow-up on their encouragement to download ReadyKern? Should there be a level of ReadyKern engagement/downloads required before CO_2 injection can commence?

- How will CTV or the County ensure that employers explain the importance of emergency notifications to their workers?

- Will CTV or the County regularly send notices to employers to download ReadyKern, acknowledging that new workers may be hired over time?

The County must also consider that ReadyKern's parent company, Everbridge, has a documented history of reliability problems. For example, in 2020, a coding error with Everbridge

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[296] Kern County Fire Dept., *ReadyKern*, https://kerncountyfire.org/education-safety/ready-kern/.
[297] *Id.* ("The service allows authorized Kern County leaders to create and rapidly disseminate time-sensitive messages to every telephone number and e-mail address stored in the notification database.").
[298] S. Najmabadi & O. Prentzel, *Emergency Alerts Were a Problem Long Before the Marshall Fire, Reports Show*, Colorado Sun (Feb. 21, 2022), https://coloradosun.com/2022/02/21/marshall-fire-emergency-alerts/.
[299] *Id.*
[300] N. Phillips, *Marshall Fire Spotlights Limitations of Opt-in Evacuation Alerts, Boulder County's Delay in Rolling Out New System*, Denver Post (Jan. 20, 2022), https://www.denverpost.com/2022/01/16/marshall-fire-evacuation-notices-alerts-everbridge/.
[301] *Id.*

meant a wildfire alert did not reach Napa and Sonoma residents.[302] In 2023, the Florida Division of Emergency Management ended its contract with Everbridge after the company "sent the wrong technical specifications" for an alert.[303] Boulder County, Colorado conducted an investigation after a massive fire in which Everbridge notifications failed, and "many residents said they never received an evacuation notice."[304] For these reasons, the County must reevaluate its reliance on ReadyKern or else offer how it plans to supplement emergency notifications because of reliability issues.

F. The Final REIR'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 Final REIR fails to meaningfully address the RDEIR Comments, meaning the County has failed to adequately disclose and analyze water supply impacts and correspondingly fails to adopt all feasible mitigation.

1. The Final REIR's description of the environmental and regulatory setting for water supply is inadequate.

As Commenters noted previously, the Final REIR needed 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 CTV I Project necessarily "reduces potential supplies for other purposes and users."[305]

The Final REIR, however, does not disclose this reality to the public and decisionmakers. Instead, the County is dismissive of the Project's impacts on local water supplies, stating: "[T]he water budget for Elk Hills . . . over 5,200 AFY available for CRC projects. This is not 'surplus water' but water CRC is entitled to utilize for a beneficial use through their water rights. . . . No other users are being deprived of water as CRC has a legal water right to utilize this water."[306]

Whether or not the Project possesses sufficient water rights for its projected usage, because demand exceeds supply in Kern County, every drop of water used by the Project

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[302] J. Serna, *As Fires Raged, County Officials Struggled With 'Confusing' Emergency Alert Systems*, LA Times (Aug. 25, 2020), https://www.latimes.com/california/story/2020-08-25/wildfires-continue-to-illuminate-holes-in-californias-emergency-alert-messaging.
[303] D. Abad, *'Unacceptably Disruptive': FDEM Ends Contract with Company That Sent Early-Morning Emergency Alert*, Channel 8 News (Apr. 24, 2023) https://www.wfla.com/news/florida/fdem-reveals-cause-of-early-morning-emergency-alert/.
[304] N. Phillips, *Marshall Fire Spotlights Limitations of Opt-in Evacuation Alerts, Boulder County's Delay in Rolling Out New System*.
[305] Kern County Planning & Nat. 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
[306] Final REIR, Vol. 3, Response 3-125 at 7-139.

represents a water supply shortfall for one or more other users. The Final REIR should address this tradeoff transparently and otherwise provide a more thorough and understandable discussion of the environmental and regulatory setting for water supply impacts.

2. The Final REIR's analysis of the Project's impact on water supply is contradictory, inaccurate, and misleading.

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

Commenters previously noted that the Recirculated Draft EIR contained conflicting statements about the source(s) of water to be used by the CTV I Project.[307] Rather than meaningfully address this comment, the Final REIR merely refers the reader to "response to comment 3-125 and Appendix G-1 – Hydrology and Water Quality Technical Documentation," neither of which addresses—let alone resolves—the County's contradictory statements. This failure to meaningfully respond violates CEQA.

Commenters also previously noted that, no matter the source(s) of water, the Recirculated Draft EIR's description of the Project's water supply demand was inaccurate and misleading. The specific problem was (and remains) Table 4.19-2:

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

As Commenters explained before, 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" because it only addresses one year of operations. Just the first phase of the Project is expected to last "26 years,"[308] meaning that operational water demand will amount to at least 506.74 acre-feet (19.49 acre-feet annually x 26 years).

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[307] See RDEIR Comments at 79.
[308] RDEIR, Vol. 1 at 1-6, 2-1, 3-2, 3-12.

The Final REIR seems to concede that the table is wrong, admitting that aside from the initial use of 75 acre-feet during the construction phase, "[t]he project will utilize 19.29 acre feet (a.f.) of water every year over the next 25 years for a total of 488 a.f. of water."[309]

Because the Project's "Total" water demand is not "94.49" acre-feet, but much larger owing to 25 or more years of annual water use, Table 4.19-2 should be corrected to accurately inform the public and decisionmakers.

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

Commenters previously pointed out that the Recirculated Draft EIR failed to adequately support its conclusion that the CTV I Project will not substantially decrease groundwater supplies.[310]

Rather that meaningfully address Commenters' critique, the Final REIR merely refers the reader to its "response to comment 3-125 and 3-130" and "Appendix G-1 – Hydrology and Water Quality Technical Documentation" none of which are responsive.[311] This failure to meaningfully respond violates CEQA.

4. The Final REIR fails to adopt all feasible mitigation for the Project's cumulative impacts on water supply.

In their previous comments, Commenters identified additional feasible water supply mitigation measures that the Project must implement to comply with CEQA.[312]

Rather that meaningfully address these mitigation measures, the Final REIR merely refers the reader to its "response to comment 3-125 and 3-130," which are not responsive.[313] This failure to meaningfully respond violates CEQA.

5. The Final REIR inadequately analyzes and mitigates disposal of oil field-produced water.

In their previous comments, Commenters noted that the Recirculated Draft EIR failed to adequately analyze or prescribe mitigation for oil field-produced water.[314]

Rather that meaningfully address the fate of oil field-produced water, the Final REIR merely refers the reader to its "response to comment 3-125 and 3-130," which are not responsive.[315] This failure to meaningfully respond violates CEQA.

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[309] Final REIR, Vol. 3, Response 3-130 at 7-140.
[310] RDEIR Comments at 80–81.
[311] See Final REIR, Vol. 3, Responses 3-131 to 3-133 at 7-140 to 7-141.
[312] RDEIR Comments at 81–82.
[313] See Final REIR, Vol. 3, Response 3-134 at 7-141.
[314] RDEIR Comments at 83–84.
[315] See Final REIR, Vol. 3, Response 3-135 at 7-141.

G. The Final REIR's Analysis and Mitigation of Biological Resources Impacts is Inadequate.

Throughout the CEQA process for the Project, Commenters have pointed out where the EIR's analysis and mitigations for biological resources impacts fall short of what is required by law. The Final REIR fails to correct a number of these deficiencies, as discussed below.

1. The Final REIR fails to adhere to recommendations from the California Department of Fish & Wildlife.

The Final REIR includes a July 1, 2024 comment on the Recirculated Draft EIR from the California Department of Fish and Wildlife (CDFW).[316] The CDFW did not mince words when addressing the Recirculated Draft EIR, calling some of the County's work "wholly misleading"[317] and issuing specific recommendations to improve the County's data disclosure and analyses. The County largely brushed off CDFW's recommendations in ways that contravene CEQA, the California Endangered Species Act, and the federal Endangered Species Act.

First**,** the CDFW called out the Recirculated Draft EIR's insufficient disclosure and analysis of species occurrence and impacts in the Elk Hills oil field. For the fully protected blunt-nosed leopard lizard (BNLL), as well as the San Joaquin antelope squirrel, giant kangaroo rat, and San Joaquin kit fox, the CDFW points out how the County ignored "extensive" and recent information about these species in the Project area.[318] CDFW noted that it could "provide some of this information if needed, as we relied heavily upon it for our more recent permitting efforts,"[319] and further identified what species survey data (and from what years and sources) it was referring to.[320]

Perhaps most striking are the CDFW's comments to the County to avoid and minimize impacts to the fully protected BNLL. (As a full-protected species, the CDFW cannot authorize incidental take for this Project.[321]) The CDFW urged the County to correct its "wholly misleading" information about the presence of BNLLs in the Project area, which the EIR supports through reconnaissance level surveys.[322] The CDFW makes clear that the County's

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[316] Letter from Julie Vance, CDFW to Keith Alvidrez, Kern County, re: Carbon TerraVault 1 Draft Recirculated Environmental Impact Report (July 1, 2024), appearing in Final REIR, Vol. 3 at pdf pp. 121–32 [hereinafter "CDFW Recirculated Draft EIR Comment"].
[317] See, e.g., CDFW Recirculated Draft EIR Comment at 4.
[318] See CDFW Recirculated Draft EIR Comment at 4–6.
[319] See CDFW Recirculated Draft EIR Comment at 4.
[320] See, e.g., CDFW Recirculated Draft EIR Comment at 5 ("CDFW recommends that the [Recirculated Draft EIR] discloses OXY/CRC's ongoing SJAS monitoring and associated detections, and historical observations to better inform the CEQA impact analysis."); see also *id.* ("[B]ut no reference was made to the substantial body of [San Joaquin antelope squirrel] detection data that exists for EHOF. . . .").
[321] CDFW Recirculated Draft EIR Comment at 2.
[322] CDFW Recirculated Draft EIR Comment at 4. The CDFW raised this exact same concern in its comments on the original Draft EIR. RDEIR, Vol. 2, App. A.6: Summary of Written Public Comments on Draft EIR (Dec. 2023) at 1068 [CDFW Letter].

approach "ignores the substantial body of biological information collected within" the Elk Hills oil field.[323]

In its responses—including to the BNLL comments—the County makes no effort to take up the data the CDFW explicitly named and recommended. The County offers no real defense for ignoring this expert agency, other than claiming incorporating data the CDFW identified "is not required by CEQA"[324] or that the information it disclosed is enough.[325]

Second, the CDFW urged consultation with the U.S. Fish and Wildlife Service under the federal Endangered Species Act (ESA) "well in advance of any Project activities" because of the potential impacts to federally listed species, including the BNLL, giant kangaroo rat, and California jewelflower, among others.[326] In its response, the County asserts that "the project proponent will be required to conduct protocol surveys in advance of any project permit application."[327] But the permit application is already underway—that is the basis for this CEQA review—and there is no indication that there has been any ESA consultation.

2. The County cannot rely on the 2014 Incidental Take Permit.

While the County finally included the Elk Hills Incidental Take Permit (2018-2014-019-04) (ITP) in the record, our concern that the ITP does not cover core CCS activities and impacts remains unchanged. The County admits that the ITP "was issued for oil field activities that would result in ground description and displacement of species."[328] This is exactly the problem. The Project involves *both* surface- *and* subsurface-disturbing activities, the most obvious of which includes the injection underground of tens of millions of metric tons of CO_2. The current ITP does not address CO_2 collection, compression, transport, injection, pore space use, or the spread of a CO_2 plume. Even the CDFW pointed out that the Project's "proposed pore space underlies a portion of the Elk Hills Conservation Area," and thus the County should "analyze any potential direct or indirect impacts to this conserved land and the associated special status species."[329] The County is simply wrong in its assertion that the ITP covers "all aspects of the proposed project."[330]

[323] CDFW Recirculated Draft EIR Comment at 4.
[324] Final REIR, Vol. 3, Response 1-009 at 7-108.
[325] See, e.g., Final REIR, Vol. 3, Response 1-008 at 7-108 (responding to CDFW Recirculated Draft EIR Comment at 8).
[326] CDFW Recirculated Draft EIR Comment at 9.
[327] Final REIR, Vol. 3, Response 1-017 at 7-110.
[328] Final REIR, Vol. 3, Response 3-171 at 7-151.
[329] CDFW Recirculated Draft EIR Comment at 8.
[330] Final REIR, Vol. 3, Response 3-171 at 7-151.

3. The Project's nighttime drilling activities remain unmitigated.

There are six protected nocturnal species in the Project area,[331] but the mitigation measures fail to adequately reduce impacts to these (and other) species from the array of nighttime Project activities expected to occur.

The Recirculated Draft EIR states that nighttime Project activities will 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,"[332] and that Class VI well drilling "typically run[s] continuously, 24 hours a day" for "up to 60 days."[333]

As we raised in earlier comments, the only nighttime-related mitigation measure for species merely concerns "directing lighting" and compliance "with applicable lighting mitigation measures."[334] Lighting is far from the only impact of nighttime construction and drilling that needs to be mitigated. The County's response does not address the 24-hour, 60 days of drilling, providing only that "construction activities" will occur "primarily" in the daytime, and operational impacts would result from "safety and security lighting."[335] This is insufficient.

4. The County must create the Worker Environmental Awareness Program now and include public input.

Mitigation Measure 4.4-11 calls for creation of a Worker Environmental Awareness Program (WEAP). The County is inexplicably deferring creation of this important program and not inviting public (including expert) input.

The WEAP is central to the County's mitigation efforts in that it will educate "construction crews and project members . . . to recognize, avoid and report any biological resources," among other things.[336] In our earlier comments on the Recirculated Draft EIR, we shared an example from the USFWS's employee education program.[337] The County did not adjust the WEAP based on the USFWS model. Because expert agencies such as the USFWS, as well as others familiar with local biological resources and CCS hazards, could have valuable input on the WEAP, the County must develop the program now and open up the development

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[331] 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).
[332] RDEIR, Vol. 1 at 4.1-24.
[333] RDEIR, Vol. 1 at 4.1-25.
[334] RDEIR, Vol. 1 at 4.4-59.
[335] Final REIR, Vol. 3, Response 3-166 at 7-150.
[336] Mitigation Measure 4.4-11.
[337] See USFWS, *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* at 6 (2011), https://www.fws.gov/sites/default/files/documents/survey-protocols-for-the-san-joaquin-kit-fox.pdf.

process to the public. The County's Response to Comments did not address why the WEAP should be created without outside input.

H. The Final REIR's Land Use Mitigation is Vague, Unenforceable, and Does Not Require What the County Argues It Does.

The RDEIR Comments pointed out that MM 4.11-7 is vague and unenforceable. In response, the County argues that the measure guarantees environmental review for future sources and CCS infrastructure:

> Mitigation Measure 4.11-7 provides for CEQA review and mitigation of impacts for any future project permitted to contribute CO2 to the proposed project reservoirs:
>
> Each CO2 source project located in unincorporated Kern County requires a zoning evaluation, its own EIR and its own Conditional Use Permit (CUP) from the County.
>
> Each CO2 source project located in an incorporated city in Kern County requires preparation of a CEQA document with the County as a responsible agency. Mitigation Measure 4.11-7 prohibits reliance on a CEQA exemption by source projects as a condition of injecting into the proposed project's reservoirs.
>
> CO2 pipelines from offsite sources that traverse unincorporated Kern County land require an EIR and CUP from the County. CO2 pipelines permitted by the California Public Utilities Commission (CPUC) require either an EIR and CUP from the County or the County's participation in the CPUC process, which must provide reasonable and feasible mitigation to protect Kern County communities.[338]

However, by its own terms, MM 4.11-7 does not require what the County argues it does, and it is still vague and unenforceable.

First, regarding sources within the unincorporated County, the Measure requires that "the listed use is approved in an appropriately zoned parcel with CO_2 capture and transport requiring an additional Conditional Use Permit and Environmental Impact Report for compliance with CEQA."[339]According to the Measure's terms, and unlike what the County argues, only the "CO_2 capture and transport" will requires an EIR, not the Project as a whole.

Second, for sources located in an incorporated city, the Measure requires that "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."[340]

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[338] Final REIR, Vol. 3, Response GR-1a at 7-19, Response GR-6c at 7-55.
[339] RDEIR, Vol. 1 at 4.11-53.
[340] RDEIR, Vol. 1 at 4.11-53.

The limitation of the Measure's environmental review requirement to "capture technology" is at odds with the County's explanation, which suggests a broader scope of future review. This makes the explanation misleading and also makes the mitigation measure ineffective. There is not even a requirement to analyze CO_2 transport. And as already explained in the RDEIR Comments, 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 for projects, it should say so explicitly. The fact that the County argues it does is not enough.

Similarly, section C.2 of the Measure does not require what the County argues it does. The section 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.[341]

Finally, like all CEQA mitigation measures, this measure cannot constitute valid mitigation of project impacts unless the County includes enforceable measures and conditions to implement the measure as part of its project approval. MM 4.11-7 sets rules for projects beyond the proposed Project, and thus requires thorough and careful implementation. The Final REIR fails to do this

The Mitigation Monitoring and Reporting Program (MMRP) for the Project merely requires incorporating the MM as a condition of approval and a written acknowledgment from the Project proponent of its requirements.[342] But the Project proponent has no authority over other projects that may send CO_2 to the Project. The conditions of approval, in turn, only state that any "additional on-site development or expansion activities" will be subject to review and approval and will require further environmental review.[343] First, the language of the condition can be understood to apply only to on-site activities, and thus limit the enforceability of MM 4.11-7 with regard to other, future projects. Beyond that, it fails to state the conditions that will be required in order for "review and approval" to move forward. Simply put, the Final REIR fails to bind the County to the specific actions that MM 4.11-7 purports to guarantee and leaves unclear how this mitigation measure will be operationalized in the County, whether through a concurrent amendment to the County zoning code or through some other mechanism. MM 4.11-7 should be revised to include clear and enforceable terms and conditions.

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341 *Gray*, *supra*, 167 Cal.App.4th at 1119.
342 Staff Report, Exhibit C: Mitigation Monitoring & Reporting Program (MMRP) at 118–19.
343 Staff Report, Draft resolutions: APPLICATION FOR CONDITIONAL USE PERMIT CASE NO. 13, MAP NO. 118; CONDITIONAL USE PERMIT CASE NO. 14, MAP NO. 118; CONDITIONAL USE PERMIT CASE NO. 5, MAP NO. 119; CONDITIONAL USE PERMIT CASE NO. 3, MAP NO. 120; CONDITIONAL USE PERMIT CASE NO. 2, MAP NO. 138 at 4.

I. The Final REIR Fails to Analyze and Mitigate Cumulatively Considerable Impacts.

The Final REIR fails to conduct an appropriate cumulative impacts analysis and support its conclusions with evidence, because it fails to consider the full range of projects and impacts that are required in a cumulative impact analysis. The revisions and Response to Comments neither excuse nor correct the lack of analysis, and lack of sufficient analysis, of probable future projects and reasonably foreseeable cumulative impacts. While the Response to Comments state that "the RDEIR done [sic] analyze cumulative impacts, guided by the practicalities and with an appropriate focus reflecting the severity of the potential cumulative impacts and their likelihood of occurrence,"[344] this conclusion is not supported by substantial evidence.

First, the Final REIR still fails to discuss any aspect of cumulative impacts relating to the Aera CarbonFrontier Project, beyond its bare listing as a cumulative project in Table 3-8. While the Final REIR now includes a brief disclosure that the CRC/Aera merger results in common ownership of that project and CTV I,[345] there is no attempt to provide any analysis at all to even assess the possibility of interaction or cumulative impacts between the two projects. The common ownership clearly suggests the project proponent is in possession of all relevant information about the plans for the CarbonFrontier Project; yet the Final REIR's statement "[b]oth projects are being processed separately, have no shared facilities and are not dependent on the other for operations" is not supported by evidence, and, importantly, the EIR presents no evidence that even a cursory analysis was performed to assess whether the two projects, taken together, may have impacts that should be considered connected or cumulative.

Second, the cumulative analysis still fails to include any meaningful discussion of the Project's CO_2 sources. For example, the EIR concedes that some projects are "'reasonably probable' [sic] future projects": "[w]here environmental review or investment of time and financial resources in anticipation of such review has progressed to the point that a project is considered a 'reasonably probable' future project, that project was included in the cumulative projects list in RDEIR Vol. 1, Table 3-8."[346] The Final REIR also states: "Lone Cypress Energy Services' hydrogen project and the Avnos DAC project. Both projects are listed in RDEIR Vol. 1, Table 3-8 and thus were included in the RDEIR's cumulative impact analysis."[347] But mere inclusion of these projects on a "list" in this EIR, rather than actually making an attempt to disclose or analyzing their potential impacts, is plainly not "analysis" supported by substantial evidence.

The Final REIR includes the following new text, apparently to justify both the use of a list in lieu of analysis, and the omission of other projects altogether:

> Other potential future CO_2 source projects are insufficiently definite for a detailed assessment of their contribution to potentially significant cumulative impacts. In addition, it is not certain what other sources are likely to contribute CO_2 for

[344] Final REIR, Vol. 3, Response GR-10b at 7-93.
[345] Final REIR, Vol. 3, Response 3-024 at 7-122 to 7-123.
[346] Final REIR, Vol. 3, Response GR-5i at 7-45.
[347] Final REIR, Vol. 3, Response GR-10c at 7-94.

> storage at the Project and there are no currently operational CCS projects in California on which to base a more concrete analysis of CO_2 source impacts. The extent of contributions to cumulative impacts from these projects are dependent on many variables and are not knowable at this time.[348]

But these statements are not supported by substantial evidence—or any evidence at all. Simply put, the County has failed to do, or to disclose, any analysis to support its claims that these future project plans are "insufficiently definite," "not certain", or "not knowable," or that these purported limitations make it impossible or unreasonable to do any analysis at all. Instead, it has just made unsupported assertions. CEQA requires more.

The Final REIR then goes on to say:

> However, any such project in the County would be accompanied by a separate CUP and associated environmental review process. It is reasonably anticipated that these future projects would be sited consistent with zoning and land use controls, would comply with all applicable federal, state, and local regulations, and would implement mitigation measures to minimize or avoid environmental impacts. As a result, these source projects are anticipated to result in impacts typical of similar scale development projects.[349]

If this statement were sufficient to excuse any cumulative impact analysis beyond the bare inclusion of a project on a list of cumulative projects, it would effectively nullify CEQA's requirement for analysis of the cumulative impacts of "reasonably foreseeable probable future projects."[350] This theory of the meaning of Guidelines section 15355 would render that section of the CEQA Guidelines meaningless in a wide range of situations—situations where courts and agencies consistently have found cumulative impact analysis necessary. The entire point of cumulative impact analysis of "reasonably foreseeable probable future projects" is to require that analysis, to the extent feasible, here and now, in this EIR; it is plainly inadequate to rely only on future environmental review of other projects instead of cumulative impact analysis, given that Guidelines section 15355 states otherwise.

Moreover, all the informational, evidentiary, and analytical inadequacies mentioned in Section I.A above and in Commenters' prior letters' similar Section I, discussing the inadequacy of the treatment of other projects (including sources that are anticipated to send CO_2 to the proposed storage facility) in the Project Description, are incorporated by reference into our critique here of the Final REIR's treatment of cumulative impacts. If those sources are not considered within the project scope and description, their impacts must be treated as cumulative, and vice versa. The County cannot avoid analysis by contending on one hand that those projects

[348] Final REIR, Vol. 3, section 7.1.3 at 7-4 to 7-5.
[349] Final REIR, Vol. 3, section 7.1.3 at 7-5.
[350] The "cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects." CEQA Guidelines, § 15355.

are not properly considered as part of this action, and on the other hand that they are not cumulative or connected projects with cumulative impacts that must be analyzed.[351]

In addition, and as discussed above in the Project Description section, the cumulative analysis fails to analyze the impacts of the Final REIR's decision to allow specific types of industries to send CO_2 to the Project. Even assuming the County cannot analyze the specific attributes of all future sources, it needed to at least analyze the cumulative impacts of allowing certain industries to send CO_2 to the Project, impacts that include and also go beyond GHG emissions. The Final REIR cumulative impacts discussion does not address these impacts, even though this EIR is the only point at which this discussion can be meaningfully had – any other analysis conducted for future sources will be done at the project level only. The County placed its new mitigation measure articulating some procedural requirements for permitting "future sources" in the land use section of the REIR, emphasizing the complete lack of analysis of any other impacts of the "future sources" list the Project is seeking to approve.

Finally, as discussed above in the context of each area of impact, and in various sections of our RDEIR Comments, the Final REIR's cumulative impact analysis of various other impact areas and resources is still flawed.

VI. THE COUNTY'S STATEMENT OF OVERRIDING CONSIDERATIONS VIOLATES CEQA

Having identified multiple significant impacts that purportedly cannot be further mitigated, the County prepared a Statement of Overriding Considerations finding, pursuant to CEQA Guidelines section 15093, that the CTV I Project's benefits outweigh those significant impacts. The Statement is deficient in multiple respects.

First, as explained above, the County failed to implement multiple feasible mitigation measures. Where an agency improperly determines that significant impacts cannot feasibly be mitigated, it "necessarily follows" that the statement of overriding consideration is invalid.[352]

Second, the Statement of Overriding Considerations is not supported by the evidence. The County failed to demonstrate that the CTV I Project will even fulfill its fundamental objective: to capture and permanently store CO_2 emissions underground. By concluding that the Project's GHG emissions will result in unavoidable significant impacts due to the risk of carbon release from leaks, and assuming that this carbon sequestration project may rely on carbon credits to offset its own emissions, the County failed to provide substantial evidence justifying approval of the Project.

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[351] Final REIR, Vol. 3, Response GR-10a at 7-91 (arguing that "[i]f future CO_2 source projects were part of the proposed project itself, as commenters claim, their impacts would be project impacts, not contributions to cumulative impacts. Conversely, comments on cumulative impacts from future CO_2 source projects are premised on the assumption that these are separate projects, not part of the proposed project").

[352] *City of Marina v. Bd. of Trustees of Cal. State Univ.* (2006) 39 Cal.4th 341, 368.

In particular, the County failed to support the claim that the Project would support California's EO B-55-18 mandate to achieve carbon neutrality by 2045.[353] As explained in these comments and in the RDEIR Comments, the Final REIR fails to show the Project is consistent with CARB's Scoping Plan, is likely to extend the life of fossil fuel facilities, and, according to its own analysis, will result in significant and unavoidable impacts from GHG emissions.

The claim that the Project "could contribute to new types of jobs and investment as the CCS project storage capacity attracts new types of industries"[354] is also unsupported by the evidence. According to the Final REIR, the Project will create about five new full-time positions.[355] The County insists throughout its Response to Comments that the Project consists only of one CO_2 source and has "independent utility."[356] Nevertheless, the County attributes to the Project the benefits of all other potential sources, while also admitting that "these industries are speculative."[357]

Finally, the County failed to identify any actual benefits of the Project beyond further perpetuating the oil and gas industry generally. The Statement of Overriding Considerations describes revenue to the Kern County General Fund and county service providers from the Project, but fails to make use of available tools to describe or quantify the costs of the impacts being overridden on economic grounds. These costs could have been quantified through use of readily available data concerning the monetary costs associated with premature death, health impacts, and loss of productivity attributable to air, climate, and water pollution.

A Stanford study found that CCS "captured the equivalent of only 10-11 percent of the emissions they produced, averaged over 20 years."[358] When the study examined the "social cost of carbon capture – including air pollution, potential health problems, economic costs and overall contributions to climate change," it ultimately "concluded that those are always similar to or higher than operating a fossil fuel plant without carbon capture and higher than not capturing carbon from the air at all."[359] The County must take these costs into account.

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For the reasons set forth above, we urge the Board of Supervisors to reject both the Final REIR and the CTV I Project at this time.

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[353] Staff Report, Exhibit B: Statement of Overriding Considerations at 4.
[354] Staff Report, Exhibit B: Statement of Overriding Considerations at 5.
[355] RDEIR, Vol. 1 at 3-38.
[356] Final REIR, Vol. 3, Response GR-1a at 7-16
[357] Staff Report, Exhibit B: Statement of Overriding Considerations at 5.
[358] T. Kubota, *Stanford Study Casts Doubt on Carbon Capture,* Stanford News (Oct. 25, 2019), https://news.stanford.edu/2019/10/25/study-casts-doubt-carbon-capture/; M.Z. Jacobson, *The Health and Climate Impacts of Carbon Capture and Direct Air Capture*, 12 ENERGY & ENVIRON. SCI. 3567 (2019), http://xlink.rsc.org/?DOI=C9EE02709B.
[359] *Id.*

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ATTACHMENT A

Evaluation of the Final Recirculated Environmental Impact Report on Geological Storage of Carbon Dioxide at the Carbon TerraVault 1 Facility in Kern County, California with a Focus on Seismicity and Well Penetrations as a Source of Leakage

Evaluation Updated to Incorporate Comments Received from County on Recirculated Draft Environmental Impact Report

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October 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: leakage during geological storage of carbon dioxide, 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 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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Comment Period Timeline

In December 2023, Volume I and Volume II of a Draft Environmental Impact Report (DEIR) (DEIR, 2023a, 2023b) was prepared by Kern County as the Lead Agency under the California Environmental Quality Act (CEQA). Earthjustice on behalf of the Center for Biological Diversity et al. submitted comments on the DEIR on March 1, 2024. These comments included a report by DiGiulio (2024a) which focused on seismic activity and well penetrations as a source of carbon dioxide (CO_2) leakage. However, Kern County had 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 the Recirculated Draft Environmental Impact Report (RDEIR) (RDEIR, 2024a, 2024b) was released for public comment. In July 2024, Earthjustice on behalf of the Center for Biological Diversity et al. submitted comments on the RDEIR. These comments included an additional report by DiGiulio (2024b) which again focused on seismic activity and well penetrations as a source of CO_2 leakage.

In August 2024, Kern County issued a response to public comments on the RDEIR essentially reflecting positions held by Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of the California Resources Corporation (CTV, 2024). CTV also contracted Cornerstone Engineering, Inc (Cornerstone Engineering, 2024) and Hasting Micro-Seismic Consulting, Inc. (Hastings Micro-Seismic Consulting, 2024) to assist in preparation of response to public comments. Also relevant to public comments is a report prepared by Blade Energy Partners (Blade Energy, 2023) to evaluate whether CO_2 injection could meet the California Air Resources Board Permanence Certification requirements (CARB, 2018).

Purpose of Report

The purpose of this report is to reply to the responses to comments on the RDEIR from the County, CTV, and consultants to CTV including Cornerstone Engineering and Hastings Micro-Seismic Consulting, and to provide actionable recommendations to move forward. In their responses to public comments, neither the County, CTV, nor Cornerstone Engineering responded directly to public comments in the order in which they were posed. Instead, these organizations issued new reports that included extensive discussion as well as their responses to comments. Relevant portions of these reports are extracted here verbatim (to maintain the fidelity of responses) and matched with public comments on the RDEIR by DiGiulio (2024b). In some instances, CTV responded to the discussion portion of the comment, so separate comments were generated to enable a reply to their response to comments. Finally, an attempt was made to make this document comprehensive in nature so that the reader does not need to refer to multiple documents to understand the nature of comments made by DiGiulio (2024b) and responses to comments.

Background

CTV, a wholly owned subsidiary of the California Resources Corporation, proposes to inject supercritical 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 millidarcies (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 is designated as the confining layer for both the 26R and A1 - A2 reservoirs in the RDEIR and in the Class VI permit for the 26R reservoir (RDEIR, 2024a, b). The Class VI permit for the A1 – A2 reservoir is under EPA review. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and clay beds. In the 26R reservoir, the Reef Ridge Shale ranges from 640 feet to 1598 feet in thickness with a mean thickness of 985 feet (RDEIR 2024b). The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points from well 355X-30R (RDEIR 2024b). The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (RDEIR 2024b). In the A1 – A2 reservoir, the Reef Ridge Shale ranges from 1122 feet to 1892 feet in thickness with a mean thickness of 1555 feet (RDEIR 2024b).

At full operation, the project is designed to inject up to 1.46 million metric tons of CO_2 per year into the 26R reservoir for 26 years for a total storage volume of up to 38 million metric tons (RDEIR, 2024b). At the A1 – A2 Reservoir, up to 0.75 million metric tons of CO_2 per year will be injected for 15 years (RDEIR, 2024b) for a total calculated storage volume of up to 11.3 million metric tons (total storage volume in A1 – A2 reservoir was not explicitly stated in the RDEIR). Ten existing wells will be converted to monitoring wells, and six existing wells would be converted into seismic monitoring wells (RDEIR, 2024a).

CTV states that pressures during injection will be maintained below initial discovery pressures which were 3,250 psi for the 26R reservoir and 4,000 psi for the A1 - A2 reservoir (RDEIR, 2024b). CTV states that maintenance of reservoir pressure at or below these levels will avoid excessive post-injection pressures that could risk CO_2 escaping geological confinement, and also minimizes the potential for induced seismicity (RDEIR, 2024b).

Discussion on 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. In the absence of other gases, CO_2 is a colorless and odorless gas. The visible white cloud commonly seen with a pressurized CO_2 release is associated with condensation of atmospheric water vapor as a result of low temperature (Spitzenberger and Flechas, 2023) due to gas expansion. A CO_2 concentration of about 5% by volume in air can cause headaches, dizziness, increased blood pressure, and difficulty in breathing within a few minutes (Spitzenberger and Flechas, 2023). A CO_2 concentration of 17% by volume in air can cause unconsciousness, convulsions, coma, and death within one minute (Spitzenberger and Flechas, 2023). Continued exposure to CO_2 concentrations above 20% will cause suffocation of most air-breathing animals (Damen et al., 2006). The U.S. Occupational Safety and Health Administration (OSHA) has set an 8-hour Permissible Exposure Level (PEL) limit of 5,000 parts per million volume (ppmv) (0.5%) for CO_2 (U.S. Department of Labor, 1988). The National Institute for Occupational Safety and Health (NIOSH) has set an Immediately Dangerous to Life or Health Concentrations (IDLH) level of 4% for CO_2 (U.S. Center for Disease Control, 1994). In the event of a well blowout, release of other gases injected with CO_2 or associated with the storage formation (e.g., methane, hydrogen sulfide) will occur, which have their own hazards.

Since CO_2 is about 1.5 times denser than air (Spitzenberger and Flechas, 2023), topography and prevailing meteorologic conditions would largely govern risk from a large-scale release. Gas buildup will be greater in valleys and low-lying areas.

As discussed in Volume II of the RDEIR (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 (Spitzenberger and Flechas, 2023).

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 (RDEIR, 2024b). 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 (RDEIR, 2024b). 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. When pressure containment is lost, the CO_2 in a wellbore converts from a supercritical "fluid" to a vapor, with significant expansive cooling. This vapor continues to expand with decreasing confining pressure as it moves up the wellbore. Flow velocities increase accordingly. Any mud or other fluid in the well can be quickly expelled leaving little hydrostatic pressure to resist reservoir influx (Skinner, 2003). A well blowout can occur in a matter of seconds after loss of containment (Skinner, 2003).

Once the CO_2 stream falls below the triple point temperature and pressure of -63°F and 76 psi, respectively, solid dry ice particles can form quickly. Several special problems result from this unique phase behavior. 1) High flowrates complicate surface intervention work and expose workers to gas moving at high velocities. Dry ice formation often results in pea- to marble-size projectiles expelled at very high velocities, sufficient to injure workers. 2) CO_2 and produced fluids form hydrates that can collect at the wellhead and other surface equipment. 3) The cold CO_2 condenses water in the atmosphere, resulting in reduced visibility in the white "cloud" around the wellbore reducing visibility. 4) Free oil and condensed miscible fluids swept out of the near-wellbore area can collect on the surface, creating a ground-fire hazard (Skinner, 2003).

A CO_2 well blowout is considered a low probability but 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, Colorado 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 (4,882 metric tons per day) and the Torre Alfina geothermal field, Italy in 1973 (Lewicki et al., 2007) having a CO_2 leakage release rate of 76 kg/s (3,283 metric tons per day) (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 ppmv (0.4 percent) at 160 feet, and 800 ppm at 330 feet (RDEIR, 2024b).

CO_2 blowouts have been known to occur during enhanced oil recovery (EOR). In 2011, an improperly plugged and abandoned well failed at the Tinsley Field, Mississippi during 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 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).

Skinner (2003) describes instances where CO_2 blowouts occurred at EOR fields in West Texas. At the first location, an injector was being serviced to replace corroded tubing joints and packer. The well began to flow unexpectedly, and the crew closed the manual blowout protector which was leaking badly. The well blew out within 30 seconds. Fluid could not be pumped into the frozen wellhead. A hot-oil truck was used to thaw the wellhead and blowout protector. Brine was then pumped down the well to regain control. At the second location, an active CO_2 injector was being converted to a reservoir pressure monitoring well. After the blowout protector failed, oil flowed with CO_2 and formed pools on the ground surface. A foam blanket was applied on the ground to prevent a fire hazard. At the third location, a blowout occurred at a well used for CO_2 injection that required a workover. The well was killed by bullheading brine down the casing.

Hence, while rare, CO_2 blowouts from wellbores, including abandoned wellbores, can and do happen.

Comments on Setbacks and Encroachment

Comment on RDEIR on Setbacks: 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 RDEIR (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).

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Risk analysis revealed no risk to the closest sensitive receptors at a 4 mile distance from the modeled worst-case CO_2 plume dispersal, a distance of 867 feet (0.16 mile) which is within the 9,104 acres of the project's CCS Surface Land Area. Beyond the modeled dispersal distance, the worst-case CO_2 plume poses no risk of health or safety impacts to receptors. Nevertheless, the RDEIR includes several mitigation measures imposing setbacks beyond the maximum dispersal distance of 867 feet: MM 4.3-6 [sic] No Class VI or Class II injection well for use in this CCS project shall be located within 4000 feet of any sensitive receptor. . .
>
> The RDEIR, Vol. 1, pp. 4.9-14 – 15, notes that no well blowouts have been reported at dedicated CO_2 storage sites to date…As described in the Cornerstone Report, a study by Jordan and Benson quantified well blowout rates in the southern San Joaquin Basin, including Elk Hills Oil Field. In the CalGEM district that includes Kern County, from 1991 to 2005, the rate of well blowout incidents in was one in 20,000 well-years for all wells in operation, with a rate of one per 15,000 well-years in oil fields utilizing thermal recovery methods (i.e., steam or hot water injection for EOR) and one per 60,000 well-years in non-thermal-recovery fields. While this study reported well blowout rates for oil and gas operations, it demonstrates that a very low risk of injection well blowouts can reasonably be expected for the proposed project's six injection wells; and any such incidents would be detected by ongoing monitoring throughout and above the injection zone under the Area of Review Corrective Action Plan required by EPA. . .
>
> Commenters claim that an injection well blowout could release many thousands of tons of CO_2, similar in scale to the pipeline rupture that occurred in Satartia, Mississippi…Mitigation Measure

4.9-14 requires the project to comply with CalGEM requirements including blowout requirements, and to reduce the incidence of well control loss by following the practices described in the American Petroleum Institute's Recommended Practice for Well Control Operations. EPA has also established integrity standards that apply to the project's injection and monitoring wells, which must be constructed so as to prevent migration of fluids out of the injection zone. The draft EPA UIC permits mandate specific standards in the well construction plan regarding well casing, cementing, and tubing and packer specifications, including meeting or exceeding ASTM International and other standards developed for such materials. In addition, the draft EPA UIC permits contain provisions to prevent well blowout: at all times, the permittee must maintain a pressure which will prevent the return of the injection fluid to the surface; the well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug must be installed which can resist the pressure; a blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well; and the permittee must limit temperature and/or corrosivity and assure that pressure imbalances do not occur. See RDEIR Vol. 2, Appendix E-3, 26R UIC Permits..."

Reply to County Response: Contrary to the County's assertion, it is likely that there have been no CO_2 blowouts at CO_2 storage sites because there are very few commercial CO_2 storage sites. As discussed, CO_2 blowouts have occurred during enhanced oil recovery. The risk of a blowout at one or more of 354 well penetrations at the Carbon Terravault 1 facility where CO_2 storage pressures will be very high cannot be disregarded by the County.

While there are safeguards to prevent a blowout at injection wells, this is not the case at legacy wells. As evidenced in west Texas (Karanam et al., 2024), blowouts can and do occur in "properly" plugged wells as a formation becomes pressurized. A substantial number of wells (> 40) in the 26R reservoir were completed prior to development of API standards on cement in 1953. At least 10 of these wells are already plugged.

EPA has established integrity standards that apply only to injection wells not monitoring wells. In §146.86 (c) (1), EPA states that "Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director." Again, this is relevant to Class VI wells not monitoring wells.

During a CO_2 blowout at Sheep Mountain, Colorado, in March 1982, the release rate was estimated to be 13,000 metric tons CO_2 per day. During a blowout at the Travale geothermal field in Italy in 1972, the estimated release rate was 4,882 metric tons per day. At the Torre Alfina geothermal field in Italy, the estimated release rate was 3,283 metric tons per day. Modeling conducted by ABS Consulting for CO_2 release from a pipeline in Appendix B.4 of Volume II of the RDEIR indicates a release rate of 104.85 lbs/s (2,054 metric tons per day) was simulated. The County must simulate the consequences of a blowout on the order of 13,000 metric tons or more of CO_2 per day. While it is acknowledged that the closest sensitive receptors are currently a 4-mile distance from injection wells, the County may require a designated setback distance greater than 4000 feet.

Comment on RDEIR on Future Encroachment: Another issue of concern is future development encroaching near land used for CO_2 storage. The land area containing wellbores and the 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 RDEIR does not address restrictions on future land use.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Commenters also claim that the RDEIR does not address restrictions on future land use within the CO_2 storage site to prevent encroaching development. The comment is incorrect. Encroachment by future development is limited by Mitigation Measure 4.11-2, which restricts use of the CCS Surface Land Area to agricultural cultivation, solar and energy storage, conservation, and permitted oil and gas exploration and production, and related provisions in Mitigation Measures 4.11-3, 4 and 5 regarding procedures for building permits, lot line adjustments and deed restrictions in the CCS Surface Land Area. No additional mitigation measures imposing setbacks or limiting encroachments are needed."

In the Cornerstone Engineering Report (Cornerstone, 2024), Cornerstone Engineering states the following:

> "The CCS Surface Land Area is defined as every section of land into which even a portion of the CO_2 plume encroaches… Accordingly, the Recirculated EIR includes mitigation measures that restrict encroachments across an area that extends even beyond the AoR. Such restrictions are highly conservative and provide an ample margin of safety."

Reply to County Response: It remains unclear how development will be restricted in the land area outside the CCS Surface Land Area which could be impacted by a major release of CO_2 in the future. The RDEIR does not provide the distance between an injection or legacy well and the boundary of the CCS Surface Land Area. Conceivably, commercial or residential development could occur sometime in the future at this boundary. The Los Angeles Basin provides an example of where oil and gas development occurred in an area where residential and commercial development was not envisioned. Wellbores are adjacent to or literally beneath existing residential and commercial structures. Wellbores must contain highly pressurized supercritical CO_2 which will not undergo significant dissolution in oil or water or mineralization even over a period of thousands of years. Hence, it is not possible to say there is no risk from a CO_2 blowout to development that is outside but close to the CCS Surface Land Area boundary.

Discussion on Mineralization of Injected CO_2

In Volume II of the RDEIR (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 on Mineralization of Injected CO_2

Comment on RDEIR on Mineralization of CO_2: 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 RDEIR (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).

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "The comment claims that the security of nonmineralized high-pressure CO_2 storage is low. The comment is correct that mineralization – a natural process in which CO_2 reacts with certain minerals to form solid carbonates – is not expected to occur at appreciable levels within hundreds of years of CO_2 injection. However, as discussed above, maintenance of reservoir pressure at or below the discovery pressure will avoid excessive post-injection pressures that could cause non-mineralized CO_2 to escape geological confinement."

Reply to County Response: The County fails to acknowledge the importance of the fact that CO_2 will be stored 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 likelihood of transition of CO_2 to more stable forms of storage (e.g., dissolution, mineralization). The County states that pressures during injection will be maintained below initial discovery pressures, which were 3,250 psi for the 26R reservoir and 4,000 psi for the A1 - A2 reservoir (RDEIR, 2024b), but fails to acknowledge that these pressures are still high. It is highly likely that leakage will occur at some unknown proportion of these legacy wells. The success or failure of this project will be primarily dictated by the magnitude of leakage at 354 plugged wellbores over hundreds to thousands of years.

Discussion on 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).

Comments on Lateral Confinement to Storage Areas

Comment on Past Hydraulic Communication of the Monterey Formation Within and Outside Anticlinal Structures: The isolation of injected CO_2 in anticlinal structures is of concern. In Volume II of the RDEIR (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 RDEIR 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.

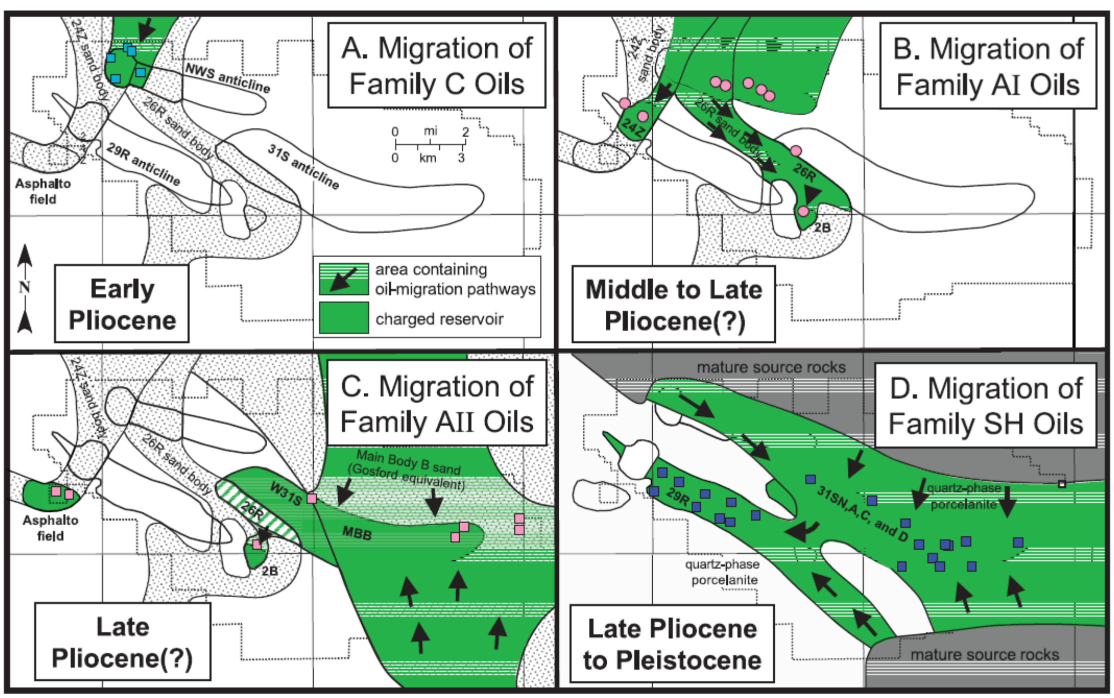

Figure 1. Migration of oil into major Stevens turbidite and porcelanite reservoirs at the Elk Hills Oil Field. (A) Family C oils are restricted to the western end of the Northwest Stevens anticline and are the least mature of the sampled oils. They may have migrated into the earliest formed traps in 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).

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.

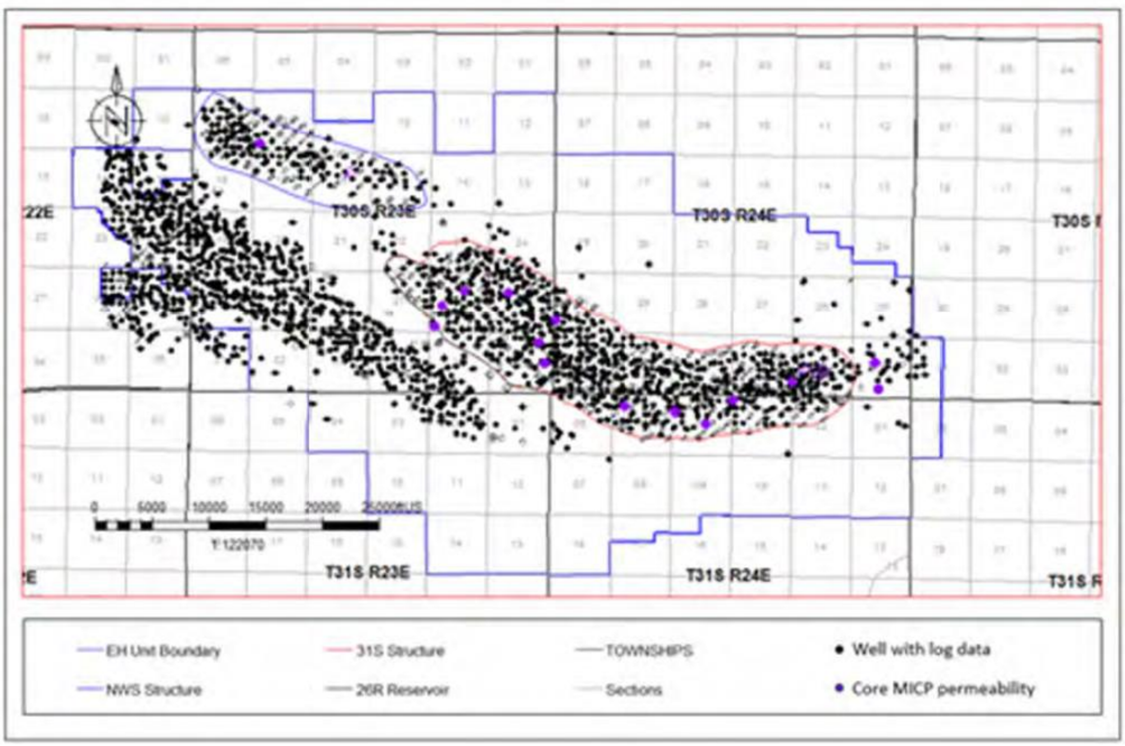

Figure 2. Wells drilled in the Elk Hills Oil Field (EHOF) that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core data from the Monterey Formation are shown in purple. Figure from Volume II of the RDEIR (RDEIR, 2024b). Note the poor resolution of the figure is due to poor resolution in the RDEIR.

<u>County Response to Comment:</u> In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

"The modeling results demonstrate confinement in the 26 R reservoir by up-dip pinch-out of the reservoir on the anticline structure and lateral confinement by reservoir edges, and confinement in the A1A1 [sic] reservoir by the anticline structure. As noted above, the operator will maintain reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does not migrate beyond the edges of the anticline structure or into the Reef Ridge shale… As such the base of the AoR will be close to the initial oil water contact."

In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

"The 26R and A1 A2 Monterey formation have maintained a distinct low pressure as compared to pressures in adjoining deposits, thus demonstrating no connection to other reservoirs. If these [sic] the 26R and A1 A2 Monterey reservoirs were connected to saline aquifers or adjacent oil and gas reservoirs, fluids would influx into the depleted 26R and A1 A2 Monterey reservoirs and keep the pressure high and in equilibrium with the surrounding reservoirs. Therefore, the distinct low pressure maintained within each formation as compared to pressures in adjoining deposits provides compelling evidence of nature's confinement of the deposits in the 26R and A1 A2 Monterey formation…

In addition, the injection of CO_2 into the 26R and A1 A2 Monterey formations proposed by the project will, pursuant to the requirements of the US EPA Class VI permit, function to restore the initial discovery pressure of 3,250 psi for the 26R formation and 4,000 psi for the A1-A2 formation. Accordingly, the proposed project would exert pressures that are no greater than existed in the natural state - a condition that retained confinement over millions of years. The fact that both geologic confinement and well integrity were upheld under these pressures provides substantial evidence that the proposed project will occur under conditions that have already been proven to hold confinement over geologic timeframes…

The commenter goes on to cite a remark from Zumberge et al (2005) which mentions that oil 'appears to have spilled' and that oil 'may 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'. This is Zumberge's opinion but it is not supported by, and is indeed contrary to, the evidence we have reviewed. As noted above, based on monitoring data gathered from existing UIC permits, historic geologic data, and the significant depleted pressures in the A1-A2 and 26R Monterey formation established in the application, the 26R and A1 A2 Monterey formation are sufficiently confined and there is no evidence of connection to other reservoirs. The figures showing the low pressure of the storage reservoir versus adjacent reservoirs are set forth in the RDEIR Appendix E-2 pages 3259, 3263, and 3498, showing the low pressure of the storage reservoirs compared to reservoirs above and below. Accordingly, as discussed above and as required by the US EPA Class VI permit, AoR for the project will be fully contained by both the pore space boundaries and structure (anticlines)...

Section 3.4.3 of the RDEIR remarks that both the 26R and A1 A2 reservoirs have 'minimal connection outside the Approved Storage Space' creating a reservoir with no connection to regional saline aquifers. While the 'minimal' connection is correct in a technical sense, read in context, and stated more directly, this means that the materials presented in the RDEIR demonstrate complete confinement of CO_2 at the volumes and locations proposed as demonstrated by the comparatively low reservoir pressure…

> Commenters suggest that additional 'wellbores should be converted to monitoring wells to monitor for both pressure perturbation and CO_2 leakage during injection'. There is no supporting evidence to require monitoring wells in addition to those required by promulgated laws, i.e. CFR §146.90(d). Moreover, the injectors and injection zone monitoring wells will also be acquiring data over the confining zone and above, including the Etchegoin. Therefore, the monitoring wells proposed by the project and required pursuant to the federal standards cited above are, in our opinion and experience, fully sufficient to monitor for and detect any CO_2 leakage during and after injection. In addition, as noted above, the Project will meet all reporting and monitoring requirements of the CARB LCFS CCS Protocol."

<u>Reply to County Response:</u> Monitoring in the Etchegoin Formation is relevant to vertical migration, not lateral migration as discussed in the County's response to comment.

In the RDEIR, the County stated that geochemical analysis of reservoirs by Zumberge et al. (2005) confirmed compartmentalization of oil and gas through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate (RDEIR, 2024b). The County is now stating that Zumberge et al.'s (2005) opinion is not supported by, and is indeed contrary to, the evidence that they have reviewed. The work of Zumberge et al. (2005) provides strong evidence of compartmentalization of oil and gas through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate in the absence of wellbores. However, the work of Zumberge et al. (2005) also provides evidence of past hydraulic communication of the Monterey Formation within and outside anticlinal structures. Because oil and natural gas are buoyant fluids, oil and gas deposits have been contained over geologic time. Because supercritical CO_2 is also a buoyant fluid, in the absence of wellbore leakage, supercritical CO_2 would also be contained unless injection is sufficient to enable migration beneath the base of the anticlinal structures (spill point).

As Cornerstone Engineering states, Class VI well regulations do not require monitoring outside the Area of Review and in the Class VI permit application, EPA did not require monitoring outside the Area of Review or anticlinal structures. However, for Class II disposal wells, EPA has required pressure monitoring outside structural closures to demonstrate containment. For instance, at the UIC Permit for the Willow Field in Payette County, Idaho, EPA required the permittee to periodically measure static reservoir pressures across structural closures and prepare an annual Boundary Effects Analysis Report (BEAR) (EPA, 2022). An assessment of requirements to protect Underground Sources of Drinking Water at this facility is provided by Tisherman and DiGiulio (2022).

Based on the work of Zumberge et al (2005) and the fact that supercritical CO_2 is buoyant, injection must be carefully managed to avoid migration of injected CO_2 outside of these reservoirs (exceedance of spill point). There are large numbers of wellbores screened in the Monterey Formation outside of storage areas. If the County refuses to follow the recommendation to convert additional wellbores to monitoring wells, it should at the very least provide an explanation to describe how leaked CO_2 as a result of exceedance of the spill point would be detected in the Monterey Formation outside the 26R and A1 – A2 anticlinal structures. One possible resolution to this issue would be to monitor CO_2 concentrations in production wells in turbidite sands in the Monterey Formation outside of anticlinal structures.

Comment on RDEIR on Monitoring Outside the Area of Review for the 26R and A1 – A2 Reservoirs: In Volume II of the RDEIR (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 RDEIR 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.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "A question was also posed during public comment period regarding response to 'unexpected changes in fluid constituents or pressure outside the A1 A2 reservoir that are not related to well integrity' and the commenter remarked that this was meaningless because 'there is no monitoring planned for outside those reservoirs'. This is not true because the testing and monitoring plan for the project includes dedicated above-zone monitoring that will identify changes in fluid constituents and pressure changes outside the injection reservoirs."

Reply to County Response: Above zone monitoring refers to vertical migration, not lateral migration outside anticlinal structures as discussed in this comment. Hence, again, there is no planned monitoring outside the Area of Review for the 26R and A1 – A2 reservoirs, meaning the County has no way to reevaluate the Area of Review as it claims.

Comment on RDEIR on Monitoring of Leakage During Enhanced Oil Recovery: In Volume II of the RDEIR (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 RDEIR 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.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The commenter questioned how leakage was monitored during enhanced oil recovery operations. Leakage in California oil and gas operating fields presents itself in either uncontrolled

releases from wells or as seeps. Multiple Class II Underground Injection Control (UIC) projects have operated and continue to operate in the Elk Hills Oil Field, regulated by Department of Conservation, Division of Geologic Energy Management (CalGEM). A number of these UICs are in the Monterey formation, and both the 26R and A1-A2 reservoirs had active UICs which operated during high and low reservoir pressure conditions. These existing permitted UICs have or are being operated with regular external and internal mechanical integrity checks on injectors and monitoring required pursuant to their applicable permits, which have been submitted to and reviewed by CalGEM to confirm that injection remains confined to the Monterey Formation. Based on this historic monitoring, there were no recordable instances of uncontrolled releases above the Reef Ridge Shale associated with existing permitted hydrocarbon extraction or injection operations nor were there documented seeps associated with leakage up through the Reef Ridge Shale. . . .

In addition, the significantly depleted current pressure of the proposed injection reservoirs when compared to formations above and below is further proof of confinement. Figure 10 included below, which can be found in RDEIR Appendix E-2, Class VI Application Narrative, illustrates the sharp contrast among pressure readings for relevant formations, an indication of natural confinement of the Carbon TerraVault 1 CO_2 injection zones. Again, the lack of either category of event – uncontrolled releases or seeps –is evidence of confinement during this period."

Reply to County Response: Lack of observation of blow outs and seeps does not constitute leak monitoring. These are catastrophic events that represent worst-case scenarios for leakage. Leakage monitoring around boreholes should be conducted using flux chambers (e.g., Kang et al. 2024, 2016), soil-gas monitoring (e.g., DiGiulio, 2010), and portable gas analyzers combined with fixed laboratory analysis (e.g., DiGiulio et al., 2023).

Discussion on 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.

Comments on Permanence Criteria

<u>Comment on RDEIR on Pressure Loss of 10 psi per year:</u> 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.

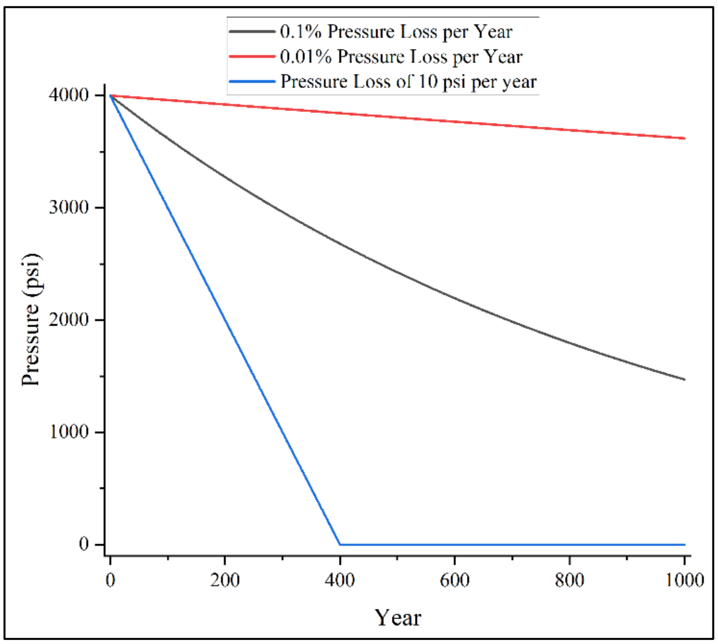

Figure 3. Simulation of 10% pressure loss per year, 0.1% pressure loss per year, and 0.01% pressure loss per year for 1000 years starting at 4000 psi.

<u>County Response to Comment:</u> In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The comment asserted that 'a pressure loss of 10 psi per year is not negligible'. The comment is inapposite to the true context of the quoted reference from the RDEIR… 'Figure 1 [Figure 4 here] from the Post-Injection Site Care and Site Closure Plan (included below) depicts modeled reservoir pressure during the injection period (years 1-25) as well as post-injection period (years 26-120). As shown in Figure 1 [Figure 4 here] below and included in the EPA Class VI Permit, in the early years post-injection (years 26-35), pressures stabilize such that a pressure change of up to 10 psi per year may (and is expressly modeled) to occur. However, in later years, as the pressures have stabilized, a pressure change of 10 psi per year is not forecasted. Measured pressures that deviate from the forecasted pressures included in Figure 1 [Figure 4 here] below would trigger a reassessment of the AoR and potentially the post injection site care period

extended as detailed in the EPA Class VI permit condition included above. Therefore, the project does not anticipate a 10-psi pressure change annually over the life of the project, nor would such a pressure change be permitted pursuant to the terms of the Class VI EPA Permit. Moreover, the commenter implies based on their 'simple back of the envelope calculation' that a pressure loss of 10 psi per year results in a decrease in pressure from 3250 psi (initial reservoir and final target pressure) to 2250 psi in 100 years resulting in appreciable CO2 loss.' First, as noted above, the commenter's assertion of a pressure loss for 100 years contradicts the modeled pressure changes, and the commenter provides nothing more than bare speculation for the assertion that a pressure loss would continue for that time period. Moreover, the pressure change of 10 psi per year does not indicate a loss of CO_2 to the atmosphere. Rather, this indicates the forecasted settling of CO_2 within the pore space of the reservoir and does not indicate a 'loss' of CO_2 as the commenter incorrectly states…

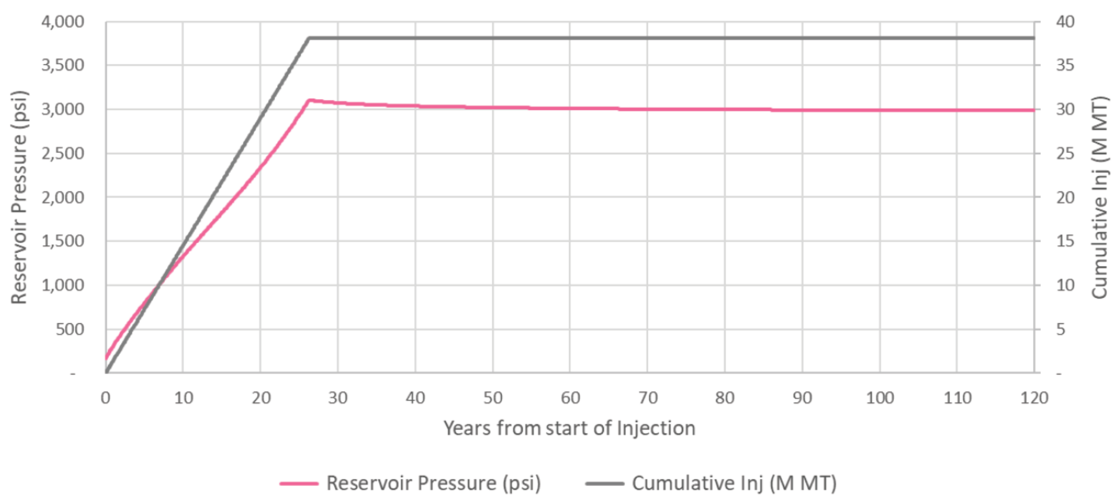

Figure 4. Simulated pressure and cumulative mass injection at 26R reservoir. Figure from Volume II of RDEIR. The poor resolution of this figure is due to poor resolution in Volume II of the RDEIR.

The commenter goes on to suggest that a target of 0.01% pressure loss per year would be more reasonable. We disagree. That very low value is both inconsistent with the reservoir simulation results and outside of the practical measured accuracy within a geologic system. Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized, that the pressure change is consistent with the model (included in Figure 1 above and in the EPA Class VI permit), and that no risk for potential vertical migration exists."

<u>Reply to County Response:</u> In Volume II of the RDEIR, CTV did not state that monitoring using a pressure loss criterion of 10 psi was limited to 9 years after cessation of injection. Continued loss of 10 psi over the lifetime of the project would indicate significant loss of CO_2. Given this clarification, monitoring a pressure loss of 10 psi per year for 9 – 10 years after cessation of injection is acceptable. This clarification should be updated and reflected in the County's Final Recirculated EIR.

<u>Comment on RDEIR on Callas et al. (2022) Journal Publication and CalGEM Plugging Requirements:</u> 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.

<u>County Response to Comment:</u> In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Commenters also assert that the RDEIR fails to adequately disclose the project's environmental setting regarding existing wellbores in the project area and their risk of leakage, and note that integrity failure of plugged and abandoned wellbores can be common based on data from Canada and various U.S. jurisdictions. In particular, the DiGiulio Report asserts that the density of plugged and abandoned wells in project area, at 9.6 wells/km2, represents a worst-case scenario for longterm CO2 storage. This claim is based on academic studies (Callas et al. 2022 and Alcalde et al. 2018) which conducted modeling based on assumed abandoned well leakage rates derived from generic datasets, across different regions with different well regulatory regimes. In California, plugging and abandonment of post-production oil and gas wells is regulated by CalGEM, which imposes detailed requirements (14 Cal. Code Regs. § 1723 et seq.) and reviews and approves abandonments by issuing final abandonment letters. Pursuant to these requirements, wellbore integrity at Elk Hills has been monitored for decades of oilfield operations. . . .
>
> For the proposed project, project-specific evaluation data were gathered on every well penetrating the reservoirs, and wells were identified for plugging and abandonment which will be carried out consistent with CalGEM requirements. RDEIR Vol. 2, Appendix E-2, P&A Procedure for Wells To Be Abandoned Prior to Injection, identifies each well requiring abandonment and provides well specific plugging plans, with pluggings to be examined by CalGEM to confirm that its requirements, designed to ensure that wells 'will not be a potential conduit for fluid migration outside the approved injection zone' (14 Cal. Code Regs. § 1724.8), are satisfied."

<u>Reply to County Response:</u> In the federal Class VI regulations, prior to operating an injection well, a cement bond and variable density log (CBL/VDL) must be conducted to evaluate cement quality outside casing (an old CBL/VDL cannot be used) in addition to a tracer survey such as oxygen-activation logging or a temperature or noise log (§ 146.87). Prior to plugging injection wells, external mechanical integrity as specified in § 146.89 must be conducted (§ 146.92) which would include an approved tracer survey such as an oxygen-activation log or a temperature or noise log. Despite other wellbores within the Area of Review containing free-phase CO_2 being exposed to the same conditions as injection wells, the Class VI rule contains no regulations for plugging legacy wells or evaluation of legacy wells prior to plugging. Hence, methods for plugging and evaluating cement outside casing prior to plugging legacy wells fall to state regulations. In the California Code of Regulations Title 14, § 1723, there are no requirements for

evaluating cement integrity outside casing above perforations or into a confining layer prior to plugging wells. Hence, if there is fluid migration outside casing prior to plugging the interior casing of legacy wells, there will be fluid migration outside casing after plugging legacy wells. If cement outside casing within the confining layer is compromised, CO_2 will migrate from the injection zone.

The greater the number of legacy wells, as in the case of Elk Hills, the greater the potential for leakage as summarized by Callas et al. (2022). Hence the work of Callas et al. (2022) is relevant to this project. A well penetration density of 9.6 wells/km^2 at the CTV facility represents a worst-case scenario for permanence for geologic storage of CO_2. At a minimum, the County should add a measure requiring CTV to work with CalGEM to conduct CBL/VDLs in wellbores prior to plugging. CBL/VDLs conducted decades earlier are not suitable for evaluation since cement commonly debonds from casing during pressure cycles and with age (Dusseault et al., 2014).

Comment on RDEIR on CARB Permanence Requirements: A permanence standard should be established in the RDEIR 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, undermining the stated purpose for this project. 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). 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.

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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), CTV states the following:

> "For CEQA purposes, it is not necessary to demonstrate that the proposed project will achieve the applicant's effectiveness metric, or any other metric drawn from the scientific literature…
>
> Nevertheless, the proposed project does have an effectiveness metric, and RDEIR Vol. 2, Appendix F provides substantial evidence indicating that it will be met. The applicant has selected the effectiveness metric from the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS) Protocol, Section C.2.2(f): a 90% probability that 99% of injected CO_2 will

remain stored within the 26R and A1A2 reservoirs for 100 years after the end of CO_2 injection…Although more stringent metrics have been proposed in the scientific literature, CARB has determined that its protocol is sufficient to qualify CCS projects for Permanence Certification….

Commenters assert that the RDEIR does not provide substantial evidence that the criterion of 90% probability that 99% of injected CO_2 will remain stored for 100 years will be met. Since the outcome after 100 years cannot be directly demonstrated, the LCFS protocol requires a site-based risk assessment, including modeling analysis, to project long-term storage effectiveness. Applying the methodology required by CARB, the site-based risk assessment determined that reservoirs 26R and A1A2 can meet CARB's LCFS permanence certification criterion of 90% probability that 99% of the injected CO_2 remains in the reservoir for 100 years after end of CO_2 injection, even under conservative assumptions."

Reply to County Response: A number of issues of concern will be addressed in this response to the County. First, federal and state regulations do not stipulate maximum leakage rates at plugged and other non-injection wellbores. The County must specify a maximum allowable CO_2 emission rate at wellbores regardless of permanence standards, because the CARB standard does not address the magnitude of leakage at wells and hence is not protective in this regard. Second, the method of simulation conducted to support the Permanence Certification is valid but flawed by inappropriate assumptions which render the conclusion that the permanence standard will be met questionable. Simulations need to be repeated using more conservative and realistic cement sheath permeability values. Third, there is little data to evaluate the current state of cement sheaths outside casing, rendering any conclusion by the County regarding permanence questionable. Cement bond/variable density logging needs to be conducted at every wellbore prior to plugging.

First, neither 40 CFR Part 98 Subpart RR regulations nor the CARB standard consider maximum allowable emission rates of CO_2 at wellbores and hence could allow substantial emissions of CO_2 without corrective action. If leakage at or in the vicinity of wellbores is detected during geological storage of CO_2, there is no regulatory mechanism to determine a maximum acceptable rate of leakage that would necessitate corrective action.

Evaluation and quantification of leakage in Class VI regulations primarily address leakage into an unauthorized formation (e.g., saline aquifer overlying a primary confining layer) and leakage into an Underground Source of Drinking Water (USDW). In Class VI regulations, surface monitoring (e.g., eddy covariance) and near surface monitoring (soil-gas sampling) can be utilized to determine potential leakage into an USDW.

However, recipients of Class VI permits must also comply with 40 CFR Part 98 Subpart RR regulations. 40 CFR § 98.448 requires development of a monitoring, reporting, and verification (MRV) plan to evaluate mass retention and leakage of CO_2. 40 CFR § 98.443(e) and 40 CFR § 98.446(f)(8) require reporting of leakage which presumably includes plugged and other non-injection wells. 40 CFR § 98.446(f)(12)(iv) requires "a description of any surface leakages of CO_2, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO_2 emitted." 40 CFR § 98.448(a)(2) requires the "identification of 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." 40 CFR § 98.448(a)(2) requires "a strategy for detecting and quantifying any surface leakage of CO_2." 40 CFR § 98.448(a)(3) requires "a strategy for establishing the expected baselines for monitoring CO_2 surface leakage."

As discussed by the County, in evaluating leakage to the atmosphere, Carbon TerraVault has selected the effectiveness metric from the CARB LCFS Protocol, Section C.2.2(f). This protocol requires a 90% probability that 99% of injected CO_2 will remain stored within the 26R and A1A2 reservoirs for 100 years after the end of CO_2 injection.

It is important for the County to account for the fact that neither EPA nor CARB define maximum leakage rates at points of leakage such as well penetrations. To illustrate what this could mean for CTV, in Volume II of the RDEIR, the County states that the project is designed to inject up to 1.46 million metric tons of CO_2 per year into the 26R reservoir for 26 years for a total storage volume of up to 38 million tons (RDEIR, 2024b). At the A1 – A2 Reservoir, up to 0.75 million metric tons of CO_2 per year will be injected for 15 years (RDEIR, 2024b) for a total calculated storage volume of up to 11.3 million metric tons (total storage volume in A1 – A2 reservoir was not explicitly stated in the RDEIR). Assuming a maximum allowable loss of 1% over the injection and 100-year post-injection phase, at the 26R reservoir, on average, emission of 81 kg/d of CO_2 per well (204 wellbores) is allowable. At the A1 - A2 reservoir, on average, emission of 36 kg/d of CO_2 per well (150 wellbores) is allowable. Because leakage at wellbores is not uniformly distributed, if leakage occurs, leakage would occur in a relatively small subset of wellbores. Hence, actual allowable leakage using CARB standards could be over an order of magnitude greater than 36 or 81 kg/d. In other words, even though very large leakage rates could be detected at wellbore locations, an argument could be made that this is somehow acceptable given CARB permanence standards even though public funds are currently being expended to plug abandoned wells having far lower methane or CO_2-equivalent leakage rates. CARB's standards for carbon storage sites therefore would allow for higher CO_2 emissions than CO_2-equivalent methane emissions present at abandoned wells currently being plugged in California and elsewhere.

While it may be true that it is not necessary for the County to demonstrate that the proposed project will achieve an effectiveness metric drawn from the scientific literature, it must be stated however, the CARB standard is not protective in regard to climate change mitigation – which is the stated main purpose of this project – and is far less stringent than corrective measures being taken at wells that are required to be abandoned in California and elsewhere. The County must therefore specify a maximum allowable CO_2 emission rate at a wellbore regardless of permanence standards. It could quantitate leakage using flux measurement developed by Kang et al (2016).

Second, the analysis is not properly supported because it relies on inappropriate assumptions. The demonstration that CARB's LCFS permanence certification criterion of 90% probability that 99% of the injected CO_2 remains in the reservoir for 100 years after end of CO_2 injection that CTV refers to is the Blade Energy Partners Report (Blade Energy, 2023). To conduct this modeling, Blade Energy Partners used the National Risk Assessment Partnership (NRAP) Open-Source Integrated Assessment Model (NRAP-Open-IAM). The use of reduced-order models such as NRAP-Open-IAM to simulate leakage through wellbores is necessary because it is extremely computationally intensive to simulate three-dimensional multiphase flow through multiple wellbores having a radius on the order of centimeters in a spatial domain on the order of kilometers (Schnaar and DiGiulio, 2009).

NRAP-Open-IAM is built on the systems-modeling approach which separates simulation of geological storage of CO_2 into three components: 1) reservoir, 2) leakage pathway, and 3) receptors. Simulations within each component are conducted separately. Component models are linked in a one-way forward manner, with the outputs from one component informing the inputs of the next. All component models are dependent upon and linked to the parameters set in the geologic stratigraphy component model. The component model allows users to define parameters describing the strata of the system, including the depth and thickness of the reservoir, overlying shale, and aquifer layers (Vasylkivska et al., 2021).

The reservoir component of NRAP-Open-IAM generates arrays representing changing pressure and fluid saturation at the top of the reservoir (reservoir-cap rock interface) over the spatial domain throughout the site performance time period of interest (Vasylkivska et al., 2021). Two reservoir component models are included with the NRAP-Open-IAM distribution - the Simple Reservoir and Lookup Table Reservoir (Vasylkivska et al., 2021). The Simple Reservoir component model uses the semi-analytical model developed by Celia et al. (2011) to simulate pressure and CO_2 saturation during CO_2 injection into a reservoir of homogeneous permeability and constant thickness. This component model is useful for preliminary, rapid estimation of reservoir response in site screening scenarios, but is not recommended for scenarios where higher spatial and temporal fidelity is needed (Vasylkivska et al. 2021).

Users that wish to incorporate more site-specific and complex reservoir response information in their model can do so with the Lookup Table Reservoir component model. This component model utilizes lookup tables from outputs created with numerical, three-dimensional, multi-phase simulators. Lookup tables provide a means for fast calculation of reservoir response (in contrast to the full-physics numerical models from which they are derived). Blade Energy Partners used output (pressure and CO_2 pore saturation) from numerical multi-phase flow modeling used to support determination of the Area of Review in the EPA Class VI permit applications for the 26R and A1 – A2 reservoirs as input for the reservoir component of NRAP-Open-IAM, apparently using the Lookup Table option.

The leakage pathway component models included with NRAP-Open-IAM are open wellbore, cemented wellbore, and multisegmented wellbore. The open wellbore component model calculates CO_2 and brine leakage along a completely uncemented legacy well. Cemented wellbore and multisegmented wellbore component models calculate CO_2 and brine leakage along fully cemented wells. Both the cemented wellbore and multisegmented wellbore component models consider the extent to which intermediate formations (i.e., porous and permeable formations overlying the primary sealing caprock but underlying the lowermost drinking water aquifer) attenuate unwanted fluid migration that might otherwise reach the atmosphere or an Underground Source of Drinking Water. However, the cemented wellbore and multisegmented wellbore component models have different configurations, sets of assumptions, and parameters, which makes them applicable to different scenarios (Vasylkivska et al. 2021). Blade Energy Partners conducted simulations using the multisegmented wellbore model but assumed that all leakage was released to the atmosphere.

Instead of generating a spatial domain, Blade Energy Partners conducted simulations at one wellbore in the 26R reservoir and one wellbore in the A1 – A2 reservoir and subsequently upscaled simulations to the entire reservoirs. Monte Carlo simulations are performed in NRAP-Open-IAM. To scale up from a single type well to the entire reservoir, Blade Energy Partners randomly selected N realizations from the pool of 2000 realizations where N is the number of wells in the reservoir. There are 150 wells in A1- A2 and 204 wells in 26R. Totaling the amount of CO_2 leaked by the N realizations yielded the total amount of CO_2

leaked by the reservoir. This step was repeated 2000 times to generate the probability distribution of the amount of CO_2 leaked by the reservoir. This method assumes that the leak risks of the wells in the reservoir are independent except for sharing the same permeability distribution. Blade Energy Partners limits simulation of leakage through wellbores between reservoirs and caprock and assumes all leakage is subsequently released to the atmosphere. Although the modeling approach utilized by Blade Energy Partners is both noteworthy and valid, the assumptions made by Blade Energy Partners during simulations present specific concerns and risks for the CTV project, as discussed below.

As described by Blade Energy Partners, key parameters in simulations include cement effective permeability, length of cement sheath, and cross-sectional area of the flow path related by the equation:

$$\frac{\text{Cement Effective permeability x cross sectional area of the flow path}}{\text{Length of the cement sheath}}$$

Blade Energy Partners states that the multi-segmented wellbore model assumes that the cross-sectional area of the flow path is the entire wellbore but since the interior of casing will be plugged, the cross-sectional area should be the cross-sectional area of the annulus between the wellbore and the casing only. For the wells in the A1 - A2 and the 26R reservoirs, the wellbore diameter is 8.75 inches, and the casing outer diameter is 7 inches. The correction factor is 0.36 (i.e., overestimated the cross-sectional flow area by 2.8 times). This correction factor assigned by Blade Energy Partners assumes that no leakage will occur through the interior of casing, which is incorrect. Plugged wells can and do leak gas through the interior of casing as evidenced of measurements conducted by DiGiulio et al. (2023) in western Pennsylvania. Leakage through casing at one plugged well exceeded 83 kg/d. This correction factor underestimates leakage and should be removed.

Blade Energy Partners states the 26R caprock thickness ranged from 200 to 490 m with a mean of 300 m while the A1 - A2 caprock thickness ranged from 1340 to 1490 m with a mean of 1400 m. Blade Energy Partners assumes that the length of the cement sheath is equivalent to the length of caprock. It is unclear whether this assumption is valid for all wellbores. For the 26R reservoir, to incorporate areas where the caprock may be thinner, Blade Energy Partners assigns a caprock overestimation factor of 1.33. However, replacing the denominator with a length of 200 m instead of 300 m results in an overestimation factor of 1.5 (300/200), not 1.33. This is a minor adjustment though. Of much greater importance is that in simulations for the A1 – A2 reservoir, Blade Energy Partners included the Lower Etchegoin Formation as part of the confining zone whereas in the RDEIR and for the Class VI permit for the A1 – A2 reservoir, only the Reef Ridge Shale is considered as caprock. At the A1 – A2 reservoir, the Reef Ridge Shale thickness varies from 342 m to 577 m with a mean of 474 m. Hence, caprock thickness used for simulations in the A1 – A2 reservoir is much greater than should have been used. This error could result in simulations significantly underestimating leakage from the A1 – A2 reservoir.

Blade Energy Partners state that they analyzed a total of 31 cement bond logs (CBLs) - 19 from 26R and 12 from A1-A2. Their report did not specify whether this is the limit of available CBL/VDLs. Blade Energy Partners state that the well annulus in the caprock was subdivided into segments. CBLs in each of these segments were classified as having good or poor cement bond based on an amplitude of 20 mv and "good VDL." The amplitude of a CBL quantitates bonding between casing and cement while the variable density log qualitatively examines bonding between cement and the borehole wall. Blade Energy Partners state that on average these wells had good cement bond between the casing and the caprock in 60% of their caprock interval. The value of 0.6 was used for 'fraction with good cement'. The problem here is that CBL/VDLs were run at the time of well completion, which in most cases is now decades old. As discussed by Dusseault et al. (2014), when evaluating oil and gas wells for plugging and abandonment, it is important to run new CBL/VDLs because significant changes in the condition of the wellbore may have occurred since the last log, and because CBL/VDL technology has improved. This is especially true for wells used for injection since pressure cycles are known to debond cement from casing. As previously discussed, new CBL/VDLs should be run in each wellbore prior to plugging. The use of decades old CBL/VDLs would likely result in underestimation of permeability and leakage.

Blade Energy Partners state that "to estimate the range of the effective permeability, the 'fraction with good cement' of each of the 31 wells that were part of the CBL analysis was examined. There was one well with no good cement bond because it failed the good VDL criteria, even though 85% of the cement sheath passed the 20mv criteria. There were two other wells with 4% and 8% good cement bond. All the other wells have more than 10%. This work assumes all the wells will have at least 10% good cement bond. Wells with less will be remediated. This 10% implies that the maximum cement permeability should be six times the adjusted mean permeability (60% divided by 10%). Including the potential of overestimating the caprock thickness (a factor of 1.33) the maximum cement permeability is eight times the mean cement permeability." Based on this logic, in simulations, Blade Energy Partners allowed a maximum cement permeability to be one-order of magnitude greater than the mean estimated permeability. Based on factors previously discussed, the maximum simulated permeability should be greater than one-order of magnitude. Also, statements by Blade Energy Partners contradict statements by CTV that no wells require corrective action prior to plugging.

Also, at least 40 wells were completed in the 26R reservoir prior to 1952. Recommendations for cement compositions and well-plugging procedures were not established by the American Petroleum Institute until 1953. Hence, the quality of cement in wellbores is highly questionable prior to the mid-1950s. Effective permeabilities of cement associated with these boreholes are likely high. It is also not understood how seismic activity has affected effective cement permeability in the past and could affect effective cement permeability in the future.

Third, the analysis is not properly supported because of lack of data regarding the current state of cement sheaths at Elk Hills.

Given that cement bond logging may have only been conducted on 31 wellbores (19 from 26R and 12 from A1 - A2) at the time of well completion, it may not even be possible to evaluate the integrity of cement outside casing at most wellbores even at the time of well completion. It may be possible for the County to conduct a third-party review of the 31 cement bond/variable density logs to establish instances where cement integrity was questionable at the time of completion. A third-party could then conduct simulations using NRAP-Open-IAM making assumptions for elevated permeability due to degradation of cement sheaths over time. In these simulations, elevated permeability could be assumed in cases where cement bond/variable density logs are absent. In addition, when simulations are conducted, maximum permeability values should be greater than one-order of magnitude than mean values. Under these conditions, attainment of a 90% probability that less than 1% leakage will occur in 100 years would be questionable.

In conclusion, the County's statements and reports in the Final EIR do not provide enough evidence to support their conclusion that they'll definitely meet CARB's standard.

<u>Comment on RDEIR on the Definition of a Storage Complex in CARB LCFS Protocol and Area of Review:</u> 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 CTV project, the storage complex would include the Etchegoin Formation. In Volume II of the RDEIR (RDEIR, 2024b), the County 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.

<u>County Response to Comment:</u> In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "Permanence of carbon sequestration is achieved through adherence to the US EPA Class VI Permit….
>
> Under EPA Class VI requirements, lateral confinement or the lateral extent of the CO_2 plume (aka the 'Approved Storage Space' or 'Area of Review' (AoR)) is determined through the use of a computational model which is submitted to and approved by the US EPA via the Class VI Permit Application materials and included in in Appendix E-2 of the RDEIR. The CARB LCFS Protocol uses the term 'Storage Complex' which is defined as 'the 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 Permanence Requirements (section C).' The term 'Storage Complex' as used in the CARB LCFS Protocol is synonymous with the term 'Approved Storage Space' or 'Area of Review (AoR)' used in the EPA Class VI requirements, and although the CARB LCFS Protocol and EPA Class VI requirements use different terms, the substantive requirement to ensure confinement of CO_2 in the Approved Storage Space / Storage Complex is applicable under both....

> The commenter goes on to inaccurately conflate the US EPA required monitoring of the dissipation interval (i.e. the geologic formations above the confining layer) with an emergency requiring remedial response. The Etchegoin Formation overlies the Reef Ridge confining layer and is identified as the above zone 'monitoring interval' in the US EPA application documents (which is synonymous with the dissipation interval). The identification of a 'monitoring interval' above the confining layer is a requirement per the US EPA Class VI regulations and was therefore identified in the project's Class VI EPA Permit application. The monitoring interval will dissipate CO_2 in the event of leakage, as it is a porous interval that will absorb CO2. The proposed monitoring well for the Etchegoin is also in alignment with Class VI regulations. Monitoring of the dedicated Etchegoin well is outlined in the Testing and Monitoring Plan provided in Appendix E-2 of the RDEIR."

<u>Reply to County Response:</u> Cornerstone Engineering states that the Area of Review is the lateral extent of the CO_2 plume, which for the CTV facility is correct since pressure propagation beyond the anticlinal structure is not anticipated. Cornerstone Engineering then states that the CARB "Storage Complex" is a three-dimensional subsurface volume to meet the requirements of the CARB LCFS Protocol. Based on Cornerstone's own description, it is difficult to understand how the Area of Review and CARB Storage Complex are synonymous – they are not. The Area of Review is a two-dimensional surface expression based on the extent of free phase CO_2 in subsurface media and elevated pressure capable of transmitting formation fluids to the base of an Underground Source of Drinking Water. In this case, it is the extent of free-phase CO_2 in 26R reservoir of the Monterey Formation. At the CTV facility, the CARB Storage Complex includes the Etchegoin Formation. Hence, the CARB Storage Complex provides for allowance for leakage into the Etchegoin Formation, whereas in EPA regulations and in the actual Class VI permit for the 26R Reservoir, the Etchegoin constitutes unallowable out of formation migration. Also, in Class VI regulations an overlying monitoring interval is not synonymous with a dissipation interval. In the Class VI application, EPA did not classify the Etchegoin Formation as a dissipation interval.

A recent example of regulatory action that would be triggered in the event of migration of CO_2 into the Etchegoin Formation is the Notice of Violation (NOV) of Safe Drinking Water Act at the CCS#2 Well (IL-115-6A-0001) Injection Well in Decatur, Macon County, Illinois issued by EPA on August 14, 2024 (EPA, 2024c). EPA subsequently issued a proposed Administrative Order on Consent (AOC) on September 19,2024 for public comment (EPA, 2024d).

In the NOV, EPA (2024c) states that Archer-Daniels-Midland (ADM) "failed to meet the requirements of the Permit and the UIC regulations in the following ways:

•Construction, operation, maintenance, plugging, or conducting any other injection activity in a manner that allows the movement of injection and formation fluids into any unauthorized zones.

•Failure to follow the Emergency Response and Remediation Plan in accordance with the Permit;

•Failure to monitor the well in accordance with the Permit."

In a letter dated 8/22/2014 from ADM to EPA, ADM stated that the leak was detected in March 2024 at one of its two deep monitoring wells, now identified as VW#2 (EPA, 2024d) due to corrosion in tubing. However, ADM apparently was aware of corrosion in tubing at the well since October 2023 (Adams, 2024). Recall from previous discussion that EPA regulates the components of Class VI injection wells not monitoring wells.

According to a spokesperson from ADM, roughly 8,000 metric tons (equivalent to about three days' worth of injection) of liquid carbon dioxide and other "ground fluid" was leaked (Adams, 2024). In a schematic released to the public by ADM (ADM, 2024), the zone of fluid movement was the Ironton-Galesville Formation which lies directly above the Eau Claire Formation – the designated confining layer. The Eau Claire Formation lies above the Mount Simon Formation used for injection of CO_2. In the AOC, EPA explicitly states that the leakage into the Ironton-Galesville Formation constitutes fluid movement into an unauthorized zone as described in the Class VI permit (EPA, 2024d) and constitutes a violation of 40 C.F.R. § 144.11, 144.51(a), and a violation of Section 1423 of SDWA, 42 U.S.C. § 300h-2 (EPA, 2024d). ADM set two plugs in VW#2 below the Ironton-Galesville Formation (EPA, 2024d). Hence, pressure and fluid monitoring can no longer be conducted in the Mount Simon Formation at VW#2.

In the AOC, EPA states that ADM must now submit a Migration Assessment Proposal for EPA approval that describes the process (including analytical methods, computational modeling, assumptions, data inputs, and data gaps) by which ADM will determine the extent of fluid migration into the Ironton-Galesville formation (EPA, 2024d). EPA also states that ADM must now identify a Migration Assessment Area of Review within the Ironton-Galesville Formation (EPA, 2024d). This is distinct from the Area of Review established for the Mount Simon Formation. Within this Area of Review, well penetrations must be identified and an overlying confining layer identified to prohibit further vertical migration (EPA, 2024d).

Based on requirements of the Class VI permit for the 26R Reservoir EPA (2024a) and the NOV and AOC for the ADM Class VI permits, it is clear that migration of CO_2 into the Etchegoin Formation would be a violation of the Class VI permits and the Safe Drinking Water Act. The County does not acknowledge nor even appear to understand that migration of CO_2 into the Etchegoin Formation would require corrective action that at a minimum would require actions currently being taken at the ADM facility.

Hence, the County treats the Etchegoin Formation as an area where leaks may technically be allowed, even though this directly conflicts with what's allowed under the federal Class VI regulations. The County appears to have a fundamental lack of understanding of how leakage into the Etchegoin Formation must trigger corrective action.

<u>Comment on RDEIR on Soil-Gas Monitoring:</u> In Volume I of the RDEIR (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, the County 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 RDEIR 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 aerial monitoring of leakage with periodic monitoring of individual well penetrations to ensure retention of CO_2 and to quantify leakage.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "For the Carbon TerraVault 1 project, monitoring features consist of the following…Periodic soil gas monitoring."

Reply to County Response: Soil-gas monitoring is not included in Attachment C (Testing and Monitoring Plan for the 26R Storage Project) and Attachment E (Post-Injection Site Care and Site Closure Plan for the 26R Project) in Volume II of the RDEIR. Soil-gas monitoring should be included with the use of eddy covariance towers.

Comments on the Emergency and Remedial Response Plans

Comment on RDEIR on the Presence of Underground Sources of Drinking Water: In Volume II of the RDEIR (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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Commenters suggest that the RDEIR's statement that the project area contains no groundwater used as drinking water that would be at risk from lateral CO2 migration (RDEIR, p. 4.9-52), and EPA permit provisions prohibiting injection that could allow movement of fluid into an underground source of drinking water (USDW). The permit provision is a requirement of EPA regulations, 40 CFR § 144.12, and also prohibits endangerment of any future USDWs, as does Mitigation Measure 4.10-4 ('The Owner/operator shall not conduct any Class VI injection activity regulated by the UIC program that discharge into any underground source of current or future beneficial use groundwater, including drinking water. The Owner/operator must demonstrate compliance with U.S. EPA Class VI UIC permit conditions.')"

Reply to County Response: It is understood that aquifer exemptions exist in Tulare Formation above the 26R and A1 – A2 reservoirs. The County has adequately addressed this comment.

Comment on the RDEIR on Re-Entry and Re-Abandonment of Leaking Wellbores: In Volume II of the RDEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1 - A2 reservoirs, the County 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.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The commenter states that 'mitigation should include assessment of leakage at wellbores and reentry and replugging of wellbores in the event of increased leakage from wellbores.' Operating oil and gas fields throughout California are currently subject to leak detection and repair programs administered by regional air districts iii. The Carbon TerraVault 1 project will similarly be subject to leak detection and repair programs administered by regional air districts, as required pursuant to the UIC permit for the project, which is a legally binding and enforceable by the US EPA, as previously stated. Operator leak detection and repairs are in addition to regular inspections by both the San Joaquin Valley Air Pollution Control District and the CalGEM, both of whom actively search for leaks….
>
> If legacy well bores, i.e. those previously plugged and abandoned within the AoR, show evidence of leakage, then re-entry and re-abandonment requirements by CalGEM or the US EPA are triggered in accordance with the requirements of the US EPA Class VI Permit, as set forth on Appendix E-2 to the RDEIR and as previously stated. Implementation of these requirements in accordance with state law is sufficient to mitigate any impacts, and additional project-specific mitigations is not necessary."

Reply to County Response: Leak detection and repair programs for methane in oil and gas fields administered by the regional air districts are not relevant to leakage of CO_2 at wellbore locations during geological storage of CO_2. There is no leak detection and repair program in the UIC program for a Class VI facility. The Class VI permit is designed to prevent leakage into a USDW, not the atmosphere. There is no wording in the Class VI permit nor in the RDEIR that states that evidence of wellbore leakage (outside of injection wells) would trigger re-entry or re-abandonment. CARB and CalGEM also do not have regulatory requirements triggering re-entry or re-abandonment of wellbores in the event of leakage.

Re-entry and re-abandonment should be triggered for a leakage rate exceeding some pre-determined value set by the County and CalGEM regardless of whether overall leakage would ultimately result in less than 1% loss over a 100-year period. As previously discussed, a loss of 1% at the 26R reservoir would on average result in an emission of 81 kg/d of CO_2 per well. Loss of 1% at the A1 - A2 reservoir would on average result in an emission of 36 kg/d of CO_2 per well. Both of these rates are far higher than allowed for CO_2-equivalent rates for oil and gas wells being plugged for leakage of natural gas.

Comment on RDEIR on Venting of CO_2 from Injection Wells: In Volume II of the RDEIR (RDEIR, 2024b) in the Emergency and Remedial Response Plan for the 26R and A1 - A2 reservoirs, the County discussed venting CO_2 from surface facilities in the event of an emergency. There is no discussion of how loss of CO_2 will be quantified during venting.

County Response to Comment: In Chapter 7 in Response to Comments, the County states the following:

> "In the 'red' operating state, the project must initiate shutdown of all injection wells, vent CO_2 from surface facilities, limit access to wellheads to authorized personnel only, communicate with local authorities to initiate evacuation plans, take a variety of steps to collect and evaluate seismic and operational data to determine whether CO_2 storage has been compromised and report to EPA. In the event of an emergency that requires venting of CO_2 from surface facilities, monitoring of flow rates of flow through surface facilities will allow for quantifying and reporting the amount released. In addition, the mitigation measures require compliance with state law (SB 905) and CARB requirements, under which CARB can shut down CO_2 injection if monitoring detects increased seismicity or CO2 leakage, thereby reducing impacts associated with injection. These requirements provide the performance standards for determining response actions including shutdown of injection wells."

Reply to County Response: It is unclear what "surface facilities" means and the County still does not clarify or explain how exactly emission of venting will be quantified.

Comment on RDEIR on Monitoring of the Etchegoin Formation: In Volume II of the RDEIR (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 a 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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "The identification of a 'dissipation interval' above the confining layer is a requirement per the US EPA Class VI regulations and was therefore identified in this application. The applicant will be monitoring both the overlying Etchegoin Formation and the Upper Tulare Formation, this is above and beyond what is required by regulation and a conservative measure which has been incorporated into the US EPA permit application."

Reply to County Response: In 40 CFR §146.83(b), EPA states the following. "The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation." In the Class VI permits for the 26R reservoir, EPA states the following. "Notwithstanding any other provisions of this permit, the permittee authorized by this permit 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).” Hence, the Etchegoin Formation is a monitoring zone in which dissipation of pressure may occur in the event of migration. Migration of CO_2 to the Etchegoin Formation still constitutes out of zone migration which would trigger corrective action or a requirement for additional monitoring. See previous discussion on corrective action measures that EPA would likely require in the event of CO_2 migration into the Etchegoin Formation.

<u>Comment on RDEIR on Inconsistency of Rate Reduction Plan at Injection Wells in the 26R and A1 – A2 Reservoir Areas:</u> In Volume II of the RDEIR (RDEIR, 2024b) for the A1 - A2 reservoir, the County 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), and in Volume II of the RDEIR (RDEIR, 2024b), the County 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.

<u>County Response to Comment:</u> Neither the County, nor CTV and its consultants, have responded to this comment.

<u>Comment on RDEIR on Need to Evaluate Leakage at All Wellbores in the Event of a Seismic Event Greater than **M** 2.7 Within One Mile of an Injection Well:</u> In Volume II of the RDEIR (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 <u>any well</u>, 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.

County Response to Comment: Neither the County, nor CTV and its consultants, responded to this comment.

Discussion of 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 multifinger 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 CTV 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 CTV project.

Comments on Evaluation of Well Penetrations from Legacy Oil and Gas Wells

Comment on RDEIR on Descriptors in Wellbore Appendices: In Volume II of the RDEIR (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.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "In oil and gas drilling, an open hole sidetrack is a drilling operation that involves drilling a secondary wellbore away from the original wellbore. An open-hole means the well does not have any casing or tubulars cemented across the reservoir section.
>
> A Sidetrack – directional cased cemented well means a well drilled in a non-vertical orientation with casing installed and cemented.
>
> Not open means the zone of interest is not perforated.
>
> Isolated means the zone of interest was perforated but has since been isolated via cemented casing or cement plugs above perforations."

Reply to County Response: The definitions of descriptors used in appendices for wellbores in the 26R and A1 – A2 reservoirs have been clarified.

Comment on RDEIR Referring to Wellbore Diagrams Being Classified as Business Confidential Information: Wellbore schematics are absolutely vital in understanding the need or potential need for corrective action. In Volume II of the RDEIR (RDEIR, 2024b), the County 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. The County 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.

The County 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, Colorado Energy & Carbon Management Commission). This unjustified lack of transparency can and indeed should erode public confidence in this project. In addition to wellbore diagrams, the County and 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 RDEIR is not a substitute for wellbore schematics.

<u>County Response to Comment:</u> In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "Per US EPA Class VI permit conditions, California Resources Corporation evaluated each well across the AoR and provided a plugging plan for each legacy well. The US EPA holds responsibility for verifying that the plan is executed and followed. In addition, CalGEM approves legacy oil and gas wells for abandonment as per their regulations including review of cement bond logs and cement to-surface records and issues final abandonment letters known as Form OG159s. Information for each well is available for public review via CalGEM well records such that providing this in the RDEIR does not further inform the environmental analysis."

<u>Reply to County Response:</u> It is difficult if not impossible for a third party to generate well diagrams and review internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc. for 354 wellbores during a public comment period. The decision by EPA and the County to allow CTV to withhold this information from the public is both surprising and disappointing. Again, this unjustified lack of transparency should erode public confidence in this project and the public and experts' ability to review and comment on it.

Without wellbore diagrams, even a cursory review of wellbores is infeasible within the comment period. It appears from the Blade Energy Partners report that cement bond logging was conducted on only 31 wellbores (19 from 26R and 12 from A1 - A2) at the time of well completion. Hence, it may not even be possible to evaluate the integrity of cement outside casing at most wellbores even at the time of well completion, because the CalGEM database only includes the necessary data on cement bond for 31 out of 354 wellbores. As previously discussed, it may be possible to conduct a third-party review of the 31 cement bond/variable density logs to establish instances where cement integrity was questionable at the time of completion and then conduct simulations using NRAP-Open IAM making assumptions for elevated permeability due to degradation of cement sheaths over time and assumptions for elevated permeability in cases where cement bond/variable density logs are absent.

Comment on RDEIR Referring to Standard Annular Pressure Testing: In Volume II of the RDEIR, the County 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." 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.

County Response to Comment: In Chapter 7, in response to comments, the County states the following:

> "The comment that mechanical integrity testing is necessary for every well is not correct; see 14 Cal. Code Regs. §§ 1724.8(a)(1), 1772 and 1774."

In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "Accordingly, the statement in RDEIR Appendix E2 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 CO2 injection or based on an agreed upon phased scheduled post CO2 injection if conditions allow' accurately summarizes CalGEM regulations in this regard. The qualifiers 'if necessary' and 'if conditions allow' in this excerpt from the RDEIR are appropriate as specific well conditions will dictate which steps are taken for each well, as determined by CalGEM according to the standards, regulatory requirements, and the agency's expertise as set forth above. Specifically, as required by CalGEM and EPA standards, each well within the AoR that penetrates the confining layer that is nominated to stay in active or idle mode is required to, and will undergo, mechanical pressure testing. Wells found lacking will require pre-operational abandonment….
>
> The commenter implies that every well slated for plugging and abandonment requires mechanical integrity testing (annular pressure testing). This is not correct. Integrity testing is only required of

wells nominated to stay in active or idle mode (see CalGEM regulations §1772 and §1774). There is no practical reason to conduct integrity testing on a well that is scheduled for abandonment as the placement of cement plugs in the wellbore will prevent fluid migration in the wellbore and prevent any casing deficiencies."

Reply to County Response: As previously discussed, 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 that the County must consider. 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). Hence, prior to plugging wells, EPA recommends internal mechanical integrity tests such as standard annular pressure tests. However, EPA did not stipulate internal mechanical integrity tests in the Class VI rule federal regulations. The County must ensure that CalGEM will conduct internal mechanical integrity tests prior to plugging non-injection wells.

Comment on RDEIR Referring to the Use of Vague Terms Describing Well Integrity: The RDEIR is replete with vague terms that lack definitions and measurable standards. In Volume II of the RDEIR (RDEIR, 2024b), the County 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?

In appendices describing wellbores in the 26R and A1 - A2 reservoirs, 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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Commenters assert that the proposed project's evaluation of wellbore risk is uncertain and lacks performance standards for wellbore integrity, due to use of qualifying terms such as 'if necessary', 'if conditions allow', 'adequate' and 'sufficient.' These terms are not intended to introduce indeterminacy; they describe conditional steps in the evaluation process established and enforced by CalGEM. See 14 Cal. Code Regs. § 1724.8(a) (emphases added): CalGEM's 'evaluation for the potential for a well to allow fluid migration will include evaluation of the cementing records.'"

Reply to County Response: In the California Code of Regulations § 1724.8(1), the following is stated. "All wells within the area of review that penetrate the injection zone for the underground injection project or a deeper zone, including directionally drilled wells that intersect the area of review in the injection zone or a deeper zone, shall be evaluated for the potential to allow fluid to migrate outside of the approved injection zone. The Division's evaluation for the potential for a well to allow fluid migration will include evaluation of the cementing records. Where cementing records are inadequate or unreliable, the Division may require a cement evaluation log. The operator should identify, and the Division confirm, wells which may require integrity testing, well logging, or monitoring in order to provide the requisite assurances that such wells will not act as conduits for fluid migration. The Division may require wells be examined, remediated, plugged and abandoned, or monitored as a condition of approval for an underground injection project if the Division is concerned that the well has the potential to allow fluid to migrate outside of the approved injection zone."

Hence, there is uncertainty on wellbore evaluation prior to plugging in CalGEM regulations. Even though all wellbores in the Area of Review in the 26R and A1 – A2 reservoirs will experience conditions identical to injection wells (direct contact with supercritical CO_2 and high pressure), EPA recommended but did not specify wellbore evaluation methods in federal regulations. Therefore, it is left to the discretion of the County and CalGEM to determine wellbore evaluation methods prior to plugging wellbores. As previously stated, the County should require cement bond/variable density logs prior to plugging.

Comment on RDEIR Referring to Regulatory Requirements on Cement Sheath Evaluation: 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 CTV 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.

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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "Where cementing records are inadequate or unreliable, [CalGEM] may require a cement evaluation log. The operator should identify, and [CalGEM] confirm, wells which may require integrity testing, well logging, or monitoring in order to provide the requisite assurances that such wells will not act as conduits for fluid migration. [CalGEM] may require wells be examined, remediated, plugged and abandoned, or monitored… if [CalGEM] is concerned that the well has the potential to allow fluid to migrate outside of the approved injection zone." These requirements "apply, at minimum and subject to augmentation by [CalGEM] on a project-specific basis, to ensure that wells within the area of review will not be a potential conduit for fluid migration outside the approved injection zone – which constitutes a performance standard for CalGEM's determinations of what is necessary, adequate, sufficient or allowed under project-specific conditions."

In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "Evaluation of wells across an AoR is addressed in CalGEM regulations 1724.8 'to ensure that wells within the area of review will not be a potential conduit for fluid migration outside the approved injection zone.' That same section goes on to state that 'The Division's evaluation for

the potential for a well to allow fluid migration will include evaluation of the cementing records. Where cementing records are inadequate or unreliable, the Division may require a cement evaluation log. The operator should identify, and the Division confirm, wells which may require integrity testing, well logging, or monitoring in order to provide the requisite assurances that such wells will not act as conduits for fluid migration. . . .'

> The well-by-well review conducted for the Project included a review of cement bond logs, cement returns to surface and operational data, which is available in public records, for each well, and based on the results of this review, repairs or remediation of cement outside casing, referred to as 'behind casing', may be required by CalGEM §1722.4 and 1723. Based on a well-by-well review, no deficiencies were identified that would require cement squeezes or casing repair for active or idle wells. Commenter provides no evidence to the contrary. Other than the set of wells slated for pre-operational abandonment, the pressure testing described above revealed no evidence of inadequate cement behind casing."

<u>Reply to County Response:</u> According to the Blade Energy Partners report, to estimate the range of the effective permeability, the "fraction with good cement" of each of the 31 wells that were part of the CBL analysis was examined. There was one well with no good cement bond because it failed the good VDL criteria, even though 85% of the cement sheath passed the 20mv criteria. There were two other wells with 4% and 8% good cement bond. All the other wells have more than 10%. This work assumes all the wells will have at least 10% good cement bond. Wells with less will be remediated. Hence, the statement by Cornerstone Engineering that "Based on a well-by-well review, no deficiencies were identified that would require cement squeezes or casing repair for active or idle wells" cannot be correct.

The County must ensure that cement bond/variable density logging is conducted on all wellbores in the Area of Review. Apparently only 31 of 354 wellbores in the 26R and A1 – A2 reservoirs had cement bond/variable density logging at well completion and these logs are decades old and hence no longer representative of current conditions.

<u>Comment on RDEIR Referring to Reported Wellbore Failure Rates in 26R and A1 – A2 Reservoirs:</u> In the RDEIR, the County 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.

<u>County Response to Comment:</u> In Chapter 7 of response to comments, the County states the following:

> "The well-by-well evaluation found no deficiencies in well casing or quality of prior plugging and abandonment. However, this does not mean that no wells were found to require abandonment prior to CO2 injection. RDEIR Vol. 2, Appendix E-2, Area of Review and Corrective Action Plans for the 26R and A1A2 projects identified 157 (out of 204) wellbores atop the 26R reservoir and 33 (out of 150) wellbores atop the A1A2 reservoir that require pre-operational abandonment. Completion of these abandonments is a requirement of EPA approval to begin injection. If deficiencies are found in already abandoned wells, then the EPA permit will require remediation to CalGEM standards."

In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The site specific, well by well evaluation of the AoR determined that no deficiencies exist in wells that will remain active or idle, or in previously plugged and abandoned wells, such that no wells that are going to remain active or idle require corrective action, and no wells that were previously plugged and abandoned required corrective action. Therefore, the remark that 0% of wells require corrective action is accurate and based on the previously conducted well-by-well evaluation. This does not suggest, however, that no abandonment work will be needed prior to operation of the project for existing active or idle wells….
>
> The project also incorporated numerous binding requirements that further reduce the potential for geologic leakage. Once analysis of legacy well bores is complete and the pre-operational abandonment program has been undertaken, scrutiny of legacy well penetrations continues via ongoing monitoring. Specifically, ongoing monitoring of the pressure and temperature profile is required as part of the US EPA corrective action plan (see excerpt below) and is proposed by the applicant throughout and above the injection zone along with monitoring of exempt waters nearer the surface (non-USDW). In addition, soil gas sampling and air monitoring across the AoR will be undertaken."

<u>Reply to County Response:</u> Again, findings in the Blade Energy Partners report confirm that statements that 0% of wellbores in the Area of Review require corrective action are untrue. Blade Energy Partners examined 31 cement bond variable density logs and determined that 3 wellbores (9.7%) require corrective action. This rate is more in line with published rates of wellbore failure rates ranging from 2 - 75% in the literature.

To more accurately determine the rate of wellbores requiring corrective action, cement bond/variable density logging should be conducted in all wellbores. Also, pressure buildup in the annular space between surface and production casing should be evaluated. Pressure build-up in this annular space indicates well barrier failure.

<u>Comment on RDEIR Referring to Whether Plugged Wellbores Meet Current CalGEM Requirements:</u> In wellbore appendices for the 26R and A1 – A2 reservoirs, what does "adequate" with P&A mean for these wellbores? 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.

County Response to Comment: Neither the County, nor CTV and its consultants, responded to this comment.

Comment on RDEIR Referring to the Thin Shale Between the A1 – A2 Reservoir and A3 – A11 Reservoir Where Enhanced Oil Recovery Will Occur During CO_2 Injection in the A1 – A2 Reservoir: In Volume II of the RDEIR (RDEIR, 2023b), the County 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 County states that the A3 - A11 reservoir is currently undergoing waterflooding which will continue during injection of CO_2 into the A1 - A2 reservoir. The County states that the A1 - A2 reservoir is hydraulically isolated from the A3 - A11 reservoir because of the following reasons. (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). (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.

The County 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 RDEIR, the County 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 RDEIR, the County 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 constitutes a major potential leakage pathway. Leakage into the A3 - A11 reservoir would constitute loss of containment.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The commenter goes on to remark on the isolation of the CO2 injection zone from the A3+ formations, noting that a 20-foot-thick shale layer is 'thin and at risk of failure'. Geologic cross-

sections included in Appendix E.2 depict the presence of this isolating feature. More importantly, the 20-foot-thick shales provides a situation wherein differential pressures have been maintained between the A1 A2 reservoir and both the overlying and underlying reservoirs. Injection of CO2 will restore the pressure to the initial discovery conditions, including sustained confinement from the A3+ formations. This provides evidence that the 20-foot thick shale layer is not at risk of failure now, and the project will in fact further reduce any such hypothetical risk by creating equilibrium (and therefore an even more stable geologic condition than exists today)."

Reply to County Response: In the comment on the RDEIR, it was not stated that the 20-foot-thick shale layer is "thin and at risk of failure". Failure generally refers to inducement of fractures. The concern here is that the mean thickness of the shale layer beneath the A1 – A2 reservoir is much thinner than the mean thickness of overlying Reef Ridge shale (by about a factor of 78) and of much greater permeability (by about a factor of 6) for a total decreased resistance to flow by a factor of about 468.

The County did not resolve the confusion regarding the A3 – A11 and A3 – A6 reservoirs. An increase in CO_2 concentrations during waterflooding of the A3 - A11 reservoir would presumably indicate leakage from the A1 – A2 reservoir. If CO_2 miscible enhanced oil recovery is conducted in the A3 - A6 reservoir, it is unclear how leakage from the A1 – A2 reservoir will be determined. The County must determine the methodology of leakage monitoring prior to regulatory approval of CO_2 miscible enhanced oil recovery in the A3 - A6 reservoir.

Comment on RDEIR Referring to Wellbores to be Used for Gas or Water Injection Below the A1 – A2 Reservoir: In Volume II of the RDEIR (RDEIR, 2024b), the County 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. The County 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.

County Response to Comment: In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "The project site includes 40 existing wells penetrating the A1-A2 reservoir which will continue to be used for existing oil and gas operations in the A3+ reservoir.

Reply to County Response: The County has clarified the use of the 40 wellbores in question.

Comment on RDEIR Referring to Annular Cement Between in the Thin Shale Layer Between the A1 – A2 Reservoir and A3 – A11 Reservoir: In Volume II of the RDEIR (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. The County 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?

County Response to Comment: Neither the County, nor CTV and its consultants, have responded to this comment.

Comment on RDEIR Referring to Monitoring in the Etchegoin Formation: In Volume II of the RDEIR, the County 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 RDEIR, the County states that the Etchegoin Formation will dissipate CO_2 injectate that may migrate upward from the injection zone. According to the RDEIR, 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, the County 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. The County 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. The County needs to justify the existence of only one monitoring well in the Etchegoin Formation.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> “Notably, Attachment C includes monitoring requirements that are designed to identify the migration of CO2 related to historic artificial penetrations in the confining zone. For example, Attachment C requires Carbon TerraVault 1 to monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 C.F.R. §146.90(d). Attachment C at 6. This requirement requires Carbon TerraVault 1 to continuously monitor the Etchegoin Formation zone for pressure and temperature changes via monitoring well 355X-26R, which will provide an indication if there may be migration of CO2 related to historic artificial penetrations in the confining zone.”

Reply to County Response: Concerns regarding physical heterogeneity and how the use of only one monitoring well will provide aerial and vertical coverage of leakage from the 26R and A1 - A2 reservoirs were not addressed in the County's response to comments.

Comment on RDEIR Referring to Use of Eddy Covariance Towers for Monitoring of Leakage from Wellbores: In Volume II of the RDEIR (RDEIR, 2024b), the County 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 do the following. (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)). (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.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "The commenter suggests that continuous aerial monitoring (which is proposed through the use of eddy covariance towers) be combined with periodic monitoring of individual well penetrations, presumably over the life of the project. However, the purpose of the broad aerial monitoring is to monitor for surface leakage over a large area, covering the AoR. Any indications of increases in CO2 flux over baseline would be reported to regulatory agencies and would trigger additional targeted point source monitoring efforts as required by applicable regulatory agencies….
>
> Air monitoring with eddy covariance towers would capture leakage from all well bores in the area. It is a far more effective method of detection potential leakage than is periodic monitoring of any selected set of wellbores (as had been suggested by the commenter).

Reply to County Response: As stated in the comment, there is concern regarding the coverage and sensitivity of eddy covariance towers. Again, it was reiterated that the use of eddy covariance towers should be combined with wellbore monitoring. Nowhere in this comment was it stated that wellbore specific monitoring should be used in lieu of eddy covariance towers. Also, nowhere in this comment was it stated that use of wellbore specific monitoring alone is a far more effective method of detection of leakage. The County must combine the use of eddy covariance towers with wellbore monitoring supplemented with flux measurement using methods developed by Kang et al. (2016) and soil-gas monitoring using methods developed by DiGiulio et al. (2019).

Discussion on Risk to Wellbores from Seismicity

Of particular concern at the CTV project site 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). 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.

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).

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, 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 CTV. 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 RDEIR, the CTV 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 RDEIR (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 CTV project. Major faults within this area are illustrated in Figure 4.

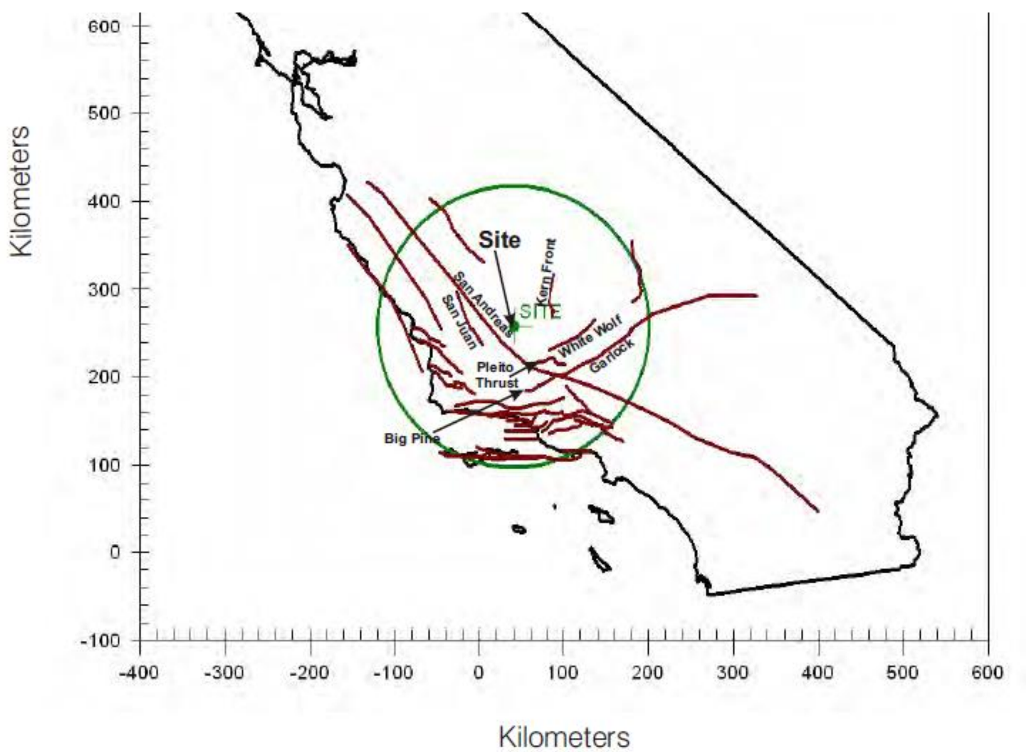

Figure 4. Identification of major faults in the vicinity of the CTV Project. Figure from Soils Engineering, Inc. in Volume II of the RDEIR (RDEIR, 2024b).

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.

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.

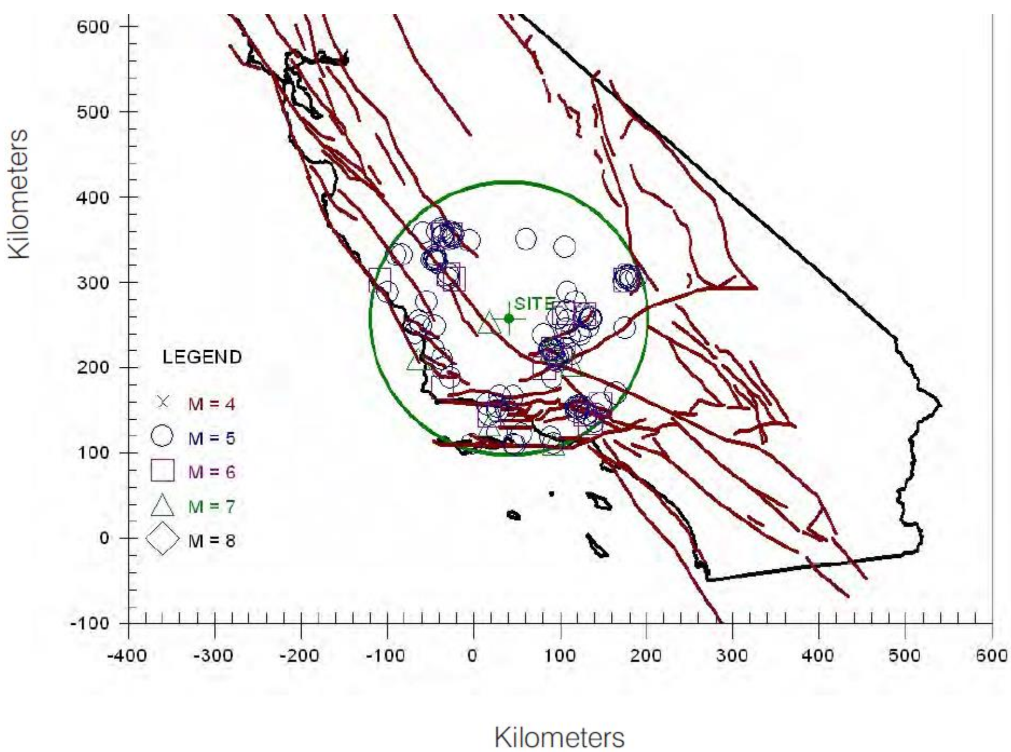

Figure 5. Magnitude of earthquakes along major faults in the vicinity of the CTV project. Figure from Soils Engineering, Inc. in Volume II of the RDEIR (RDEIR 2024b).

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).

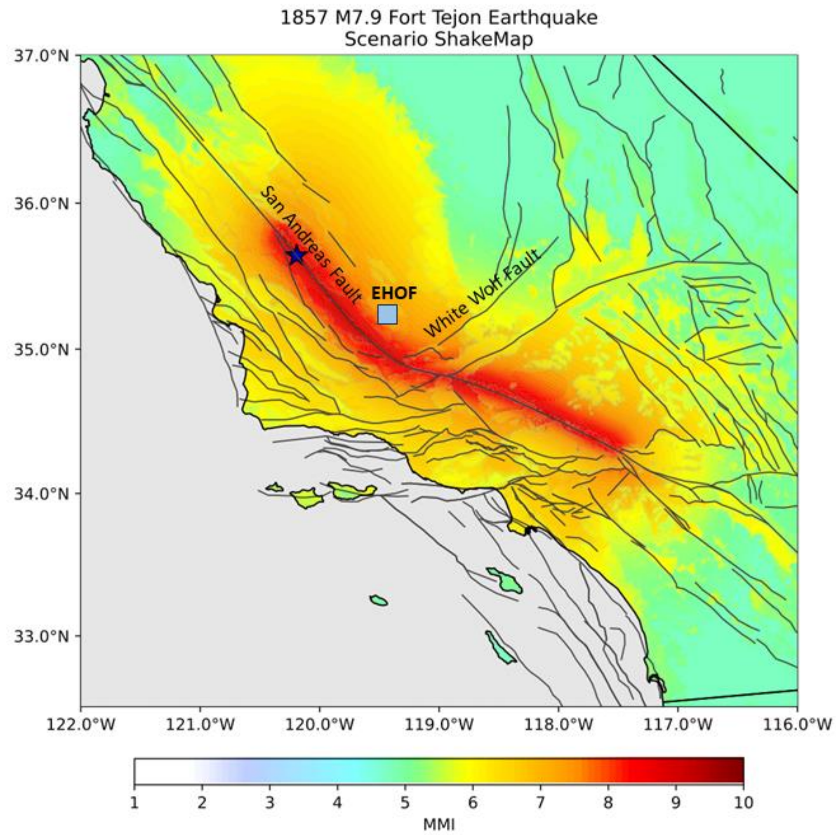

Figure 6. Location of faults in southern California and of the 1857 Tejon earthquake on the San Andreas Fault and estimated Modified Mercalli Intensity. The Epicenter illustrated by dark blue star. Approximate location of EHOF illustrated by light blue box. San Andreas and White Wolf Faults identified. Figure modified from Southern California Earthquake Data Center.

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).

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).

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.

As discussed by Soils Engineering, Inc. in Volume 2 of the RDEIR (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.

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.

<u>Hazard Evaluation of Natural Seismic Events</u>

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 RDEIR (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) (g refers to fraction of gravitational acceleration) 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.

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's Unified Hazard Tool calculates peak ground and spectral acceleration at a site for all the earthquake locations and magnitudes believed possible in the vicinity of a site. Each of these magnitude-location pairs is believed to happen at some average probability per year. Small ground motions are relatively likely while 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).

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 RDEIR (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

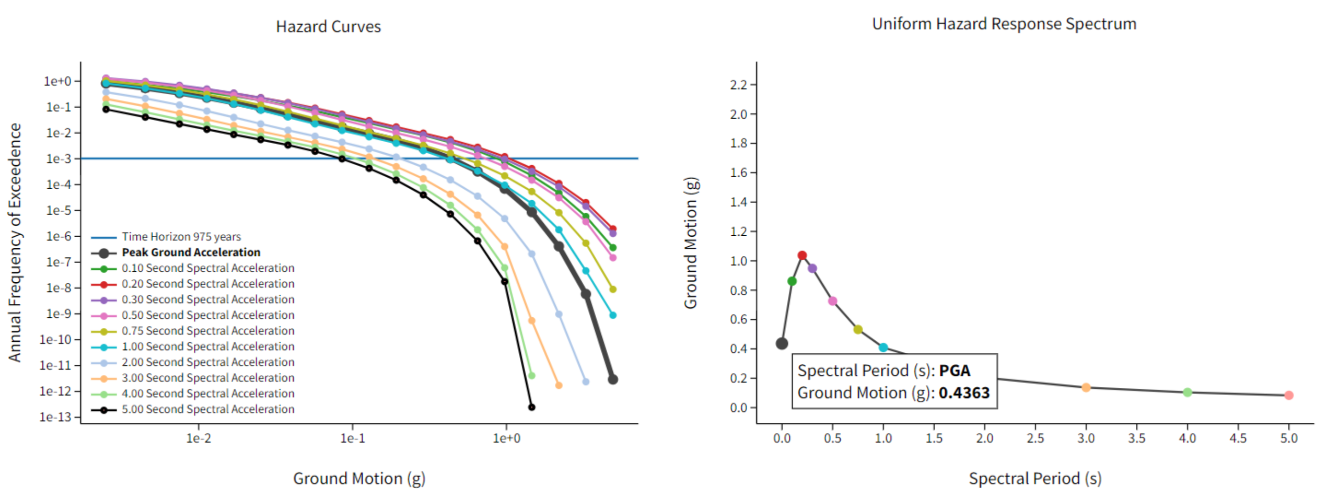

Figure 7. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 5% in 50 years. For an annual frequency of exceedance of 1.025E-03 or return period (inverse of frequency of exceedance) of 975 years, peak ground acceleration = 0.4363g (43.63% of the gravitational constant).

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) (performed here) 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 $r^* \leq 1$ where $r^* = r(1+0.5r)$ and r = probability as recommended by USGS (USGS, 2024).

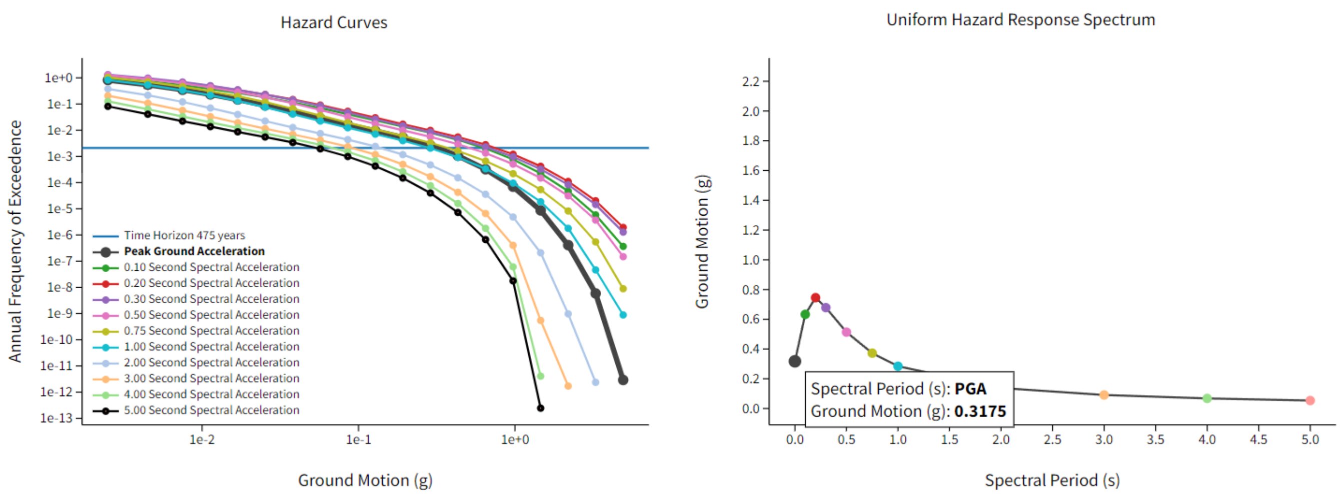

Figure 8. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 10% in 50 years. For an annual frequency of exceedance of 2.105E-03 or return period (inverse of frequency of exceedance) of 475 years, peak ground acceleration = 0.3175g (31.75% of the gravitational constant).

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 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 in the Class VI permit applications 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 in the Class VI permit applications that the 26R reservoir is continuous across the Area of Review and the sands pinch-out up-dip and on the channel edges. As such, EPA states that 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 CTV 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 CTV 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 CTV 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 (1.5 psi) can induce seismicity. Hence, analysis conducted by the County in the RDEIR and Class VI permit applications does not properly address eliminate the potential for induced seismicity at the CTV project.

<u>Seismic Monitoring Network Design</u>

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.

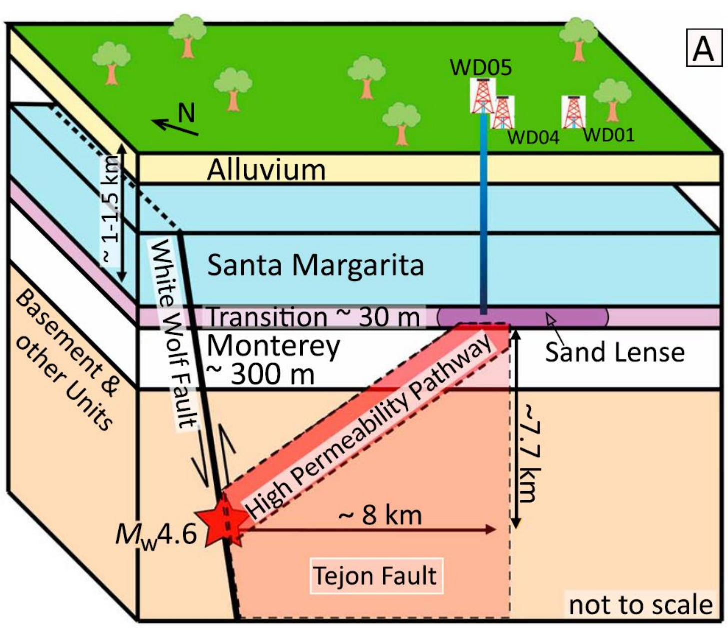

Figure 9. Schematic representation of pressure migration along a high-permeability fault between the Tejon Oil Field and a M 4.6 seismic event along the White Wolf Fault.

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, the County will monitor seismicity with a network of surface and shallow borehole seismometers. Specifically, the County will deploy 6 sensor locations (borehole and near surface) most of which are outside the Area of Review. The County 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.

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 RDEIR 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.

Comments and Response to Comments on Seismicity

Comment on RDEIR on the Relevancy of the U.S. Department of Energy's Guidelines on Evaluating the Potential Impact of Tectonic and Induced Seismicity: Given uncertainty in potential impact due to natural and induced seismicity during geological storage of CO_2, protocols developed by DOE's 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 CTV.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "The commenter urges that recommendations authored by Templeton et al be followed when assessing the impacts of natural and induced seismicity. Those recommended practices include characterization of seismic activity within at least a 200 km radius of the area of interest and proposes outreach to stakeholders to establish 'stakeholder risk tolerance' presumably for vibratory loads and frequencies that the public may find acceptable. The recommended practices are not appropriate for the Project because they are written for proposed undertakings in a more populated area with tectonic connectivity that extends hundreds of kilometers from the area of interest and pertain to projects with an established risk of inducing seismicity. Neither is the case for Carbon TerraVault 1. Besides, the 1952 Kern County earthquake was the largest event on record within a 200 km radius of the project such that the conclusions would not change."

Reply to County Response: Guidelines developed by the U.S. Department of Energy (Templeton et al., 2021, 2023) to evaluate the potential impact of tectonic and induced seismicity during geologic storage of CO_2 are not limited to populated areas. As Templeton et al. (2023) state, recommendations are envisioned to serve as general guidelines, setting expectations for operators, regulators, and the public. They contain a set of seven actionable focus areas, the purpose of which are to deal proactively with seismicity issues, and the County should consider them for this project.

Comment on RDEIR on Potential Wellbore Leakage at the 26R Reservoir after the 1952 Kern County Earthquake: In Volume II of the RDEIR (RDEIR, 2024b) for both the 26R and A1 - A2 reservoirs, the County 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 RDEIR, 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, the County's statement in this regard is misleading and should be removed from the RDEIR.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "The 26R reservoir was discovered in the 1940's and a significant number of delineation/development wells were drilled prior to 1952 and used to monitor the reservoir. The 26R reservoir was placed on full production and injection in the 1970's. In addition, the Shallow Oil Zone which overlays the 26R reservoir, has been in production since 1910. Even with that

extent of field development at the time, there were no containment issues resulting from the 1952 earthquake."

Reply to County Response to Comment: The Kern earthquake occurred on July 21, 1952. Based on the Appendix outlining wellbores in the 26R reservoir, there appears to be 40 boreholes that were drilled prior to this date, of which 10 are plugged. In the absence of catastrophic documented failure of boreholes during the 1952 Kern earthquake, which apparently did not occur, a review of standard annular pressure tests and cement bond logs conducted before and after the Kern earthquake would be useful in assessing damage to casing and the cement sheath outside casing. Absent this comparison or the availability of data to make this comparison, it is not possible for the County to definitely determine whether the 1952 Kern earthquake caused damage to wellbores in the 26R reservoir. A similar evaluation would need to be conducted for the shallow oil zone.

Comment on the RDEIR on Magnitude of Seismic Event Necessitating Evaluation of Leakage from Wellbores: In Volume II of the RDEIR (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** $\geq$ 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. The County should consider this measure in its analysis.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "Steinbrugge and Moran concluded that '...none of the (San Joaquin Valley) oil fields has sustained losses of any consequence to subsurface equipment.' In addition, the proposed project will follow the CARB LCFS CCS Protocol which includes this requirement for post-earthquake integrity testing. The CARB LCFS CCS Protocol includes a **M** 2.7 trigger for integrity testing and the EPA Class VI includes a **M** 3.5 trigger for integrity testing. The project will adhere to the more stringent of these requirements (the **M** 2.7 trigger). This demonstrates with empirical evidence that the Level of Significance for Impact 4.7-2 is correct and should remain Less than Significant as stated in the RDEIR."

Reply to County Response to Comment: The County has clarified that it will adhere to the more stringent **M** 2.7 trigger for evaluation of surface and subsurface damage due to induced seismic activity as a result of injection of CO_2 in the 26R and A1 – A2 reservoirs. However, the problem remains that the County will not evaluate damage to subsurface equipment including wellbores for a major tectonic seismic event unrelated to injection of CO_2.

As discussed, for the project location, a peak ground acceleration rate of 0.4363g was estimated having a 5% probability of exceedance in 50 years. This is approximately equivalent to a 9.8% probability of exceedance in 100 years. A further examination of the hazard curves indicates a peak ground acceleration of 0.3175g having a 10% probability of exceedance in 50 years and a 19% probability in 100 years. A near 20% probability of major ground shaking in the project area over the next 100 years (the time frame within CTV's responsibility or care) is concerning. The County should specify and CARB should require a ground motion parameter such as peak ground acceleration within the Area of Review, which would trigger an evaluation of wellbore integrity.

Comment on the RDEIR on Evaluation of Seismic Risk: 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 RDEIR 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 RDEIR.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "Seismic risk to subsurface structures such as well bores is markedly different. Lateral forces on well bores are far less than at ground surface due to the stabilizing nature of surrounding soils, and wellbores are therefore subject to different seismic risk factors than that applicable to above ground structures. Specifically, seismic risk for legacy well bores is associated with the possibility for fault movement. Appendix E-1 to the RDEIR characterizes known faults throughout the region and concludes that 'It is unlikely that ground rupture could occur at this site since it is not located within 500 feet of a suspected active fault' and that 'ground failure is highly unlikely at this site.'"

Reply to County Response to Comment: If seismic activity is shallow, shaking will be intense. If seismic activity is deep (natural or tectonic earthquakes), seismic waves attenuate or grow weaker on their way to the surface. Damaging earthquake waves are largest near the hypocenter, or origin of the earthquake. In the absence of soil liquification and ground rupture, for natural seismic activity, the potential for wellbore damage would be expected to increase with depth. Since the facility is outside the Alquist-Priolo Earthquake Fault Zoning area, the primary concern is not ground rupture but ground movement, including deep ground movement, due to a major seismic event.

Fragility functions of wellbores are unknown. As discussed, seismic activity can and has damaged wellbores like those at Elk Hills. 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). 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.

The County should therefore ensure and CARB should require a ground motion parameter such as peak ground acceleration within the Area of Review which would trigger an evaluation of wellbore integrity.

Comment on the RDEIR on Mitigation of Measure 4.7-1: In Volume 1 of the RDEIR (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 $\geq$ 5, PGA $\geq$ 0.05g, PGV $\geq$ 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.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "There are no mapped faults in the Carbon TerraVault 1 AoR. Appendix E-1 to the RDEIR characterizes known faults throughout the region and concludes that 'It is unlikely that ground rupture could occur at this site since it is not located within 500 feet of a suspected active fault' and that 'ground failure is highly unlikely at this site.'"

In Chapter 7 on response to comments, the County states the following:

> "Although Mitigation Measure 4.7-1 refers to a seismic monitoring plan, it and the other mitigation measures listed above also include required actions in response to seismic events, including compliance with the requirements of EPA Class VI permit's Emergency and Remedial

> Response Plan, that would avoid, reduce, correct or compensate for impacts associated with natural or induced seismicity per the definition of mitigation in CEQA Guidelines § 15370."

Reply to County Response to Comment: Again, as stated in the comment on the RDEIR, unlike induced seismicity as a result of injection of CO_2, monitoring of natural seismicity is not mitigation. Again, the Level of Significance for Impact 4.7-1 should be changed from Less than Significant to Significant and Unavoidable. The County should ensure and CARB should require a ground motion parameter such as peak ground acceleration within the Area of Review which would trigger an evaluation of wellbore integrity.

Comment on RDEIR on Level of Significance for Impact 4.7-2: In Volume II of the RDEIR (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 CTV 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 $\geq$ 5, PGA $\geq$ 0.05g, PGV $\geq$ 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.

County Response to Comment: In Chapter 7 on response to comments, the County states the following:

> "Compliance with building regulations and design standards will protect surface structures from significant seismic impacts, while oil and gas wellbore integrity is regulated by CalGEM under

> the California Public Resources Code and implementing regulations, and Class VI injection wellbore design is regulated by EPA under the Safe Drinking Water Act and its UIC program. (See below regarding injection well blowout risk.) These agencies have developed standards to prevent fluid from migrating between underground rock layers in the setting of California's geology and seismic regime. The proposed project must comply with federal and state regulations which ensure that the well bores are designed and constructed so as to retain integrity given the project's geologic setting."

In the Cornerstone Engineering Report (2024), Cornerstone Engineering states the following:

> "Commenters on the RDEIR argue there are no standards for wellbore integrity, which, they argue, could be an issue in the context of seismic events and the release of CO2. Commenters are incorrect and fail to recognize the specific standards that apply to the Carbon TerraVault 1-I injection and monitoring wells as established by the US EPA in the UIC Permits, Attachment E (Well Construction Plan). The construction and repurposing of injection and monitoring wells will occur during pre-operational testing and must be constructed, in part, to prevent migration of fluids out of the injection zone. See 26R UIC Permits, Attachment E at 3. As part of Attachment E, the UIC permit mandates specific standards regarding well casing, cementing, and tubing and packer specifications, including meeting or exceeding standards development for such materials by, for example, ASTM International. See 26R UIC Permits at 8-9; Attachment E at 3-4. . . .
>
> The commenter additionally remarked that '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, and as such the Level of Significance for Impact 4.7-2 should be changed from Less than Significant to Significant and Unavoidable.' We disagree with the commenter's stated opinion. In an assessment of production changes and subsurface damages after the 1952 earthquake, no damage was reported to any well, either shallow or deep, producer or injector at Elk Hills (Steinbrugge, K. V. and Moran D., Vol. 44, No. 2, April 1954 An Engineering Study of the Southern California Earthquake of July 21, 1952 and its Aftershocks)."

<u>Reply to County Response to Comment:</u> EPA and CalGEM regulations do not address damage to wellbores as a result of seismic activity. As previously stated, the Kern earthquake occurred on July 21, 1952. Based on the Appendix outlining wellbores in the 26R reservoir, there appears to be 40 boreholes that were drilled prior to this date of which 10 are plugged. In the absence of catastrophic documented failure of boreholes during the 1952 Kern earthquake, which is apparently lacking, a review of standard annular pressure tests and cement bond logs conducted before and after the Kern earthquake would be useful in assessing damage to casing and the cement sheath outside casing. Absent this comparison or the availability of data to make this comparison, it is not possible for the County to definitely determine whether the 1952 Kern earthquake caused damage to well bore in the 26R reservoir.

<u>Comment on RDEIR on Classification of Risk from Seismic Activity:</u> 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

<u>County Response to Comment:</u> In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "DiGiulio also says further examination of the seismic hazard curves at the end of Appendix E-1 shows 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; at a probability of exceedance of 5% in 50 years, extending the hazard curve to 975 years gives a peak ground acceleration of 0.4363g. He concludes: '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.'
>
> As stated above, the Magnitude 7.5 1952 Kern County Earthquake is the largest magnitude event within a 200 km radius of Elk Hills within the Last 100 Years. The Mercali Motion Index (MMI) at Elk Hills ranged from 6.5 at the east end of the field to 5.0 at the west end, with peak ground accelerations ranging from 0.12g – 0.18g. The Paloma field, to the southeast had MMIs in the 7.4 range, with ground accelerations of ~0.3g–0.35 g, with no documented damage to wellbores during the quake. The Wheeler Ridge and Mountain View Fields, both with MMIs of 8.5+ and ground accelerations of 0.5+, similarly had no documented wellbore damage. Accordingly, wellbores within the AoR have withstood ground accelerations of up to 0.5g without damage. Given improvements in technology and maintenance standards in accordance with CalGEM regulations means that current wellbores are even less likely to sustain damage than the wells extant in 1952."

<u>Reply to County Response to Comment:</u> As stated in comments on the RDEIR, there is 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, within a 100-year period at the CTV Project area. Since the probability of occurrence in a 100-year period is greater than 5% and the consequence of the occurrence is potentially substantial, risk

should be classified as high. Even if the consequence of the occurrence was classified as insubstantial, risk would be classified as medium, not low or less than significant level as specified by the County.

Comment on RDEIR on Pressure Diffusion Capable of Inducing Seismicity: 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 (1.5 psi) can induce seismicity (e.g., Goebel et al. 2016, Keranen et al. 2014, Hornback et al. 2015). Hence, analysis conducted by the County in the RDEIR and Class VI permit applications does not eliminate the potential for inducted seismicity at the CTV project.

County Response to Comment: In the Cornerstone Engineering Report (FREIR, 2024), Cornerstone Engineering states the following:

> "The commenter suggests that seismicity along a fault may be induced by injection of fluids with pressure differentials of as low as 1.5 psi. We disagree. The commenter has not provided any evidence of carbon or other fluid injection at depths, pressures, and in geologic conditions similar to Carbon TerraVault 1 that induced seismicity, and we are aware of no such evidence. To the contrary and as discussed above, pursuant to binding provisions of the EPA Class VI Permit, the project will function to restore to original reservoir pressure and would therefore exert similar pressures as existed in the natural state, a condition that retained pressure over millions of years. Appendix E-2 of the RDEIR cites a final reservoir pressure of 3,250 psi for 26R and 4,000 psi for A1-A2 at CO_2 injection shut-in. These final pressures are 'significantly below the Reef Ridge confining shale estimated geomechanical tensile failure pressure of ~7,500 psi'. This pressure differential between the injection zone and overlying and underlying layers creates confidence in containment. Limiting the reservoir to the initial pressure, as required by EPA permit, therefore mitigates the potential for induced seismicity that would result from the project, even in the context of an unknown fault, because it will restore conditions to original reservoir pressures. . . .
>
> The commenter also questions whether there could be a possibility of pressure transmission below the Monterey Formation. The Monterey Formation is itself ~4,000' thick, with more than 2,000' of rock with a documented tensile failure pressure 3,000 psi greater than the maximum final reservoir injection pressure, below the base of the injection target. Below the base of the Monterey (the nearest well, 987-25R, reached basement, low-grade metamorphic rock, at 18,761'), are ~9,000' of sedimentary strata. All these formations have pressures much higher than 4,000 psi, which will preclude any downward fluid migration or induced seismicity. The Carbon TerraVault 1 project proposes a maximum bottomhole injection pressure that is less than fracture pressure. What this means in geologic terms is that fluid such as CO2 and the pressure exerted thereon would remain in the zone of injection and not transmit to the underlying formation."

In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "The circumstances associated with oilfield induced seismicity in other parts of the United States have been shown to be inapplicable in California. These issues were examined in two reports by the California Council for Science and Technology (CCST): 'Advanced Well Stimulation Technologies in California' (2014) and 'An Independent Scientific Assessment of Well Stimulation in California, Potential Environmental Impacts of Hydraulic Fracturing and Acid

Stimulations' (2015). CCST found that the lack of seismicity for hydraulic fracturing in California is consistent with the relatively shallow injection depths and small injection volumes in California operations, compared to other parts of the United States where high volume fracturing uses much greater quantities of water at greater depths. Regarding wastewater injection, CCST found that the likelihood of such induced seismicity is low in California compared to other regions in the U.S; the zones at which the rocks are rigid enough to accumulate enough stress to cause significant earthquakes are relatively deep in California, and significantly deeper than the oil and gas development and wastewater disposal zones; oil and gas production in California occurs in sedimentary basins, which are less susceptible to induced seismicity from wastewater injection; typical wastewater volumes injected per well in California are generally less than those associated with well stimulation operations in other parts of the country where induced seismicity has occurred; and operation of injection wells has had little effect on seismicity rates in Kern County. . . .

The DiGiulio Report identifies one potentially injection-induced seismic incident at the Tejon Oil Field, associated with the White Wolf Fault. However, in that case the White Wolf fault was intersected by a seismically active fault in proximity to the oil field, with an 11 km high permeability pathway along the seismically active part of the fault. Under such circumstances, seismicity may be induced in a fault that is favorably oriented for slipping by injecting fluids at pressure differentials as low as 1.5 psi. However, the DiGiulio Report provides no evidence of induced seismicity at depths, pressures and geological conditions similar to the project site."

<u>Reply to County Response to Comment:</u> As stated in comments on the RDEIR, pressure propagation (commonly referred to as pressure diffusion) can occur over large distances and depths during injection of fluids. Pressure diffusion occurs at much lower pressures than tensile fracture pressure. Effective stress changes as little as 1.5 psi induce seismicity (e.g., Goebel et al. 2016, Keranen et al. 2014, Hornback et al. 2015). As Templeton et al. (2023) discuss, recent studies indicate that effective stress changes on the order of 100 kPa (~14.5 psi) or less can be found near earthquake hypocenters which supports the observation of long-distance induced seismicity (Keranen et al., 2014, Barbour et al., 2017, Norbeck and Rubinstein, 2018, Zhai et al., 2020).

Gobel (2015) compared seismicity rates due to fluid injection operations in Oklahoma and California and arrived at the following conclusion. "The view that injection-induced earthquakes have been avoided successfully in California in the past because of less invasive injection operations is likely erroneous. The scarcity of induced seismicity in California might simply be an expression of lower stresses at injection depth and lack of large-scale hydraulic connectivity within hydrocarbon basins. Although less probable, earthquakes might be induced in California through injection in areas of active faulting." Hence, the potential for induced seismicity is less in California compared to other states such as Oklahoma. This however, does not eliminate the potential for induced seismicity at the CTV facility.

As stated by the California Geological Survey (CGS, 2024), "While the project area is not located in an Earthquake Fault Zone presently mapped by CGS the site may contain unmapped faults not included in the USGS database." Hence the study conducted by Goebel et al. (2016) for the Tejon Oil Field is not irrelevant. As previously discussed, 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).

Hence, while keeping pressure in the 26R and A1-A2 below initial development pressure reduces the potential for induced seismicity, it does not eliminate the potential for induced seismicity at the CTV project.

Comment on RDEIR on Pressure Transmission Below the Monterey Formation: 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 RDEIR (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, the County 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.

County Response to Comment: In Chapter 7 of Response to Comments (FREIR, 2024), the County states the following:

> "The site-specific evaluation in RDEIR Vol. 2, Appendix F, found no record of induced seismic events from extensive water and gas injection at the Elk Hills Oil Field. Based on geological conditions and the operational history of injection at Elk Hills, the evaluation concluded that probability of occurrence is less than 1% and the severity of the risk is insubstantial since, if induced seismicity were to occur, it would be at a low level based on the record of water injection operations."

Reply to County Response to Comment: USGS has attempted to quantify the probability of seismic risk in areas of increased seismicity, especially Oklahoma, due to injection of oil and gas wastewater (Petersen et al., 2017). USGS has not quantified areas of increased induced seismicity due to injection of CO_2, let alone a specific area such as the CTV facility. An attempted quantification of induced seismicity due to injection of CO_2 has not been attempted at any facility. This attempted quantification of induced seismicity of less than 1% at the CTV facility is not substantiated in the RDEIR and should be treated with considerable skepticism.

Comment on RDEIR on Specification of a Ground Motion Parameter to Trigger Evaluation of Wellbores: 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.

County Response to Comment: Neither the County, nor CTV and its consultants have responded to this comment.

Comment on RDEIR on Deployment of Sensors: 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.

County Response to Comment: In the Hastings Micro-Seismic Consulting Report (HMSC, 2024), HMSC states the following:

> "HMSC has deployed standard borehole seismic sensor capable of recording very weak motion and more than suitable for recording seismic events within the local AoI. For larger events we are also pulling data from the USGS/SCSN which will provide both location and magnitude information for larger events in the AoI and surrounding area. HMSC disagrees with the technical recommendations made by the reported cited in this comment because they are less well suited to record weak ground motion, than the technology deployed for the EHSA, and the Templeton report's generalize recommendations fails to adequately account for the regional accelerometers that have been already installed as part of the USGS Shake Alert Network which covers the Project AoI. Accordingly, the additional accelerometer stations noted in the comment are, in HMSC's experience and based on our extensive knowledge of the system, not necessary for locating smaller seismic events. The current design more than meets the substantive goals reflected in this comment. Accordingly, in our opinion, no additional mitigation measures or revisions are required."

Reply to County Response to Comment: The Hastings Micro-Seismic Consulting Report has satisfied concerns with this issue.

Comment on RDEIR on Deployment of Sensors: In Volume II of the RDEIR (RDEIR, 2024b), the County 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, the County will monitor data from nearby (~5-8 mi) 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.

County Response to Comment: In the Hastings Micro-Seismic Consulting Report (HMSC, 2024), HMSC states the following. "Templeton et al. (2021) suggest the use of 3 component seismic sensors and 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. The AG2 sensor deployed in the primary stations use standard 3 component sensors oriented in the standard orthogonal configuration (X, Y and Z axis) and are capable of up to 15 deg of tilt. The current design and hardware of the array, and the hardware fully satisfies (and improves upon) the frequency range of 2-100 Hz with a sampling rate of 250sps within the AoI. If we run at 500sps the frequency range can be increased to 200Hz. These sensors more than meet this suggestion/requirement."

Reply to County Response to Comment: The Hastings Micro-Seismic Consulting Report has satisfied concerns with this issue.

Comment on RDEIR on Vertical Resolution of Sensors: 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 RDEIR (RDEIR, 2024b), The County 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.

County Response to Comment: In the Hastings Micro-Seismic Consulting Report (HMSC, 2024), HMSC states the following:

> "The design of the array, and based on HMSC's 30-plus years of experience, is capable of location accuracy of 100 meter horizontal and 200 meter vertical, providing an even more precise location accuracy than recommended by the commenter. Over time the velocity model may be updated based on the presence of additional seismic data points detected over time. This will further improve the model's ability to precisely identify the locations of the events, thereby enhancing the accuracy even farther beyond the standards recommended by the commenter."

Reply to County Response to Comment: The Hastings Micro-Seismic Consulting Report has satisfied concerns with this issue.

Comment on RDEIR on Data Logging of Sensors: 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 RDEIR (DEIR, 2024b), the County 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 RDEIR, but should be.

County Response to Comment: In the Hastings Micro-Seismic Consulting Report (HMSC, 2024), HMSC states the following:

> "The Gecko data logger is a 32-bit data logger with timing accuracy provided via a GPS system with a timing accuracy of 30 nanoseconds, so more than meets the commenter's suggestion."

Reply to County Response to Comment: The Hastings Micro-Seismic Consulting Report has satisfied concerns with this issue.

Comment on RDEIR on Reporting to CARB: 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 RDEIR.

County Response to Comment: In the Hastings Micro-Seismic Consulting Report (HMSC, 2024), HMSC states the following:

> "As part of HMSC monitoring efforts much of these requirements will be completed in real time with the automatic DAS SEISMOSPHERE software. The standard location information provided by the DAS SEISMOSPHERE software includes, but not is not limited to:
>
> • Date and Time in UTC
> • Latitude/Longitude and Depth Relative to Mean Sea Level (MSL) in KM
> • Magnitude and Intensity
> • Peak Ground Acceleration (PGA) in mm
>
> Detailed seismic reports on seismic event locations can be generated at any time by CRC through the secure Web Portal or via HMSC's analysts upon request. Plots can also be provided in both 2D and 3D using proprietary software developed by HMSC, which will clearly indicate the location and distance of the epicenter from the Project, as well as many other such information. These plots can also be animated into "movies" if required and/or requested. An example plot is shown in figures 16, 17 and 18 below of a HMSC project in Colorado and seismicity near wastewater injection wells. In our experience, the initial report can be provided within the requirements and will provide coverage for all aspects, as outlined in the comments above.

Reply to County Response to Comment: The Hastings Micro-Seismic Consulting Report has satisfied concerns with this issue.

Conclusions and Actionable Recommendations

A potential CO_2 blowout at a legacy well remains of considerable concern. Blowouts at CO_2 storage and geothermal fields have actually occurred. During a CO_2 blowout at Sheep Mountain, Colorado, in March 1982, the release rate was estimated to be 13,000 metric tons CO_2 per day. Air dispersion modeling was conducted for CO_2 release from a pipeline at a release rate of 104.85 lbs/s (2054 metric tons per day). The County must simulate the consequences of a blowout on the order of 13,000 metric tons or more of CO_2 per day.

There are a large number of wellbores screened in the Monterey Formation outside the 26R and A1 – A2 reservoirs. In lieu of converting some wellbores to monitoring wells, the County should provide an explanation of how leaked CO_2 as a result of exceedance of the spill point would be detected in the Monterey Formation outside the 26R and A1 – A2 anticlinal structures.

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 km2), a well penetration density of 9.6 wells/km^2 represents a worst-case scenario for permanence for geologic storage of CO2 (Callas et al., 2022). CO_2 will be stored as a highly pressurized (3,250 psi for the 26R reservoir and 4,000 psi for the A1 - A2 reservoir) 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). The success or failure of this project will be primarily dictated by the integrity of 354 plugged wellbores over hundreds to thousands of years. Given the importance of wellbore integrity, the California Geologic Energy Management (CalGEM) division should require cement bond/variable density logs (CBL/VDLs) for all unplugged wells to evaluate cement outside casing, especially within the Reef Ridge Shale – the confining layer. Apparently only 31 of 354 wellbores in the 26R and A1 – A2 reservoirs had cement bond/variable density logging at well completion and these logs are decades old and hence no longer representative of current conditions. Use of CBL/VDLs conducted decades earlier are not suitable for evaluation since cement commonly debonds form casing during pressure cycles and with age (Dusseault et al., 2014). CalGEM should also require measurement of pressure in the annular space between production and surface casing as annular pressure is an indication of well barrier failure. Plugging the interior of well casing does little to prevent fluid migration occurring through the cement sheath outside casing.

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). However, there are no federal permanence standards for geologic storage of CO_2. 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 (CARB, 2018). The method of simulation conducted to support the Permanence Certification is both noteworthy and valid but flawed by inappropriate assumptions. For instance, during simulations for the A1 – A2 reservoir, the Lower Etchegoin Formation was considered as part of the confining zone whereas in the RDEIR and for the Class VI permit for the A1 – A2 reservoir, only the Reef Ridge Shale is considered as caprock. Hence, the caprock thickness used for simulations in the A1 – A2 reservoir was much greater than what should have been used. Also, there were only 31 of 354 wellbore CBL/VDLs available for inspection to evaluate cement outside casing and these CBL/VDLs are decades old. There was no allowance for cement sheath deterioration over years of pressure cycling and complete lack of information on cement sheath integrity for over 91% of wellbores. Also, at least 40 wellbores were completed or plugged prior to cement standards being developed by the American Petroleum Institute in the early 1950s. Hence, actual cement permeability is likely to be greater than what was simulated. The California Air Resources Board should require simulations to be repeated using new CBL/VDLs and higher more realistic permeability values.

Up to 1.46 million metric tons of CO_2 per year will be injected into the 26R reservoir for 26 years for a total storage volume of up to 38 million tons. Up to 0.75 million metric tons of CO_2 will be injected into the A1 – A2 reservoir per year for 15 years (RDEIR, 2024b) for a total calculated storage volume of up to 11.3 million metric tons. Assuming a maximum allowable loss of 1% over the injection and 100-year post-injection phase, on average, emission of 81 kg/d of CO_2 per well (204 wellbores) is allowable in the 26R reservoir and 36 kg/d of CO_2 per well (150 wellbores) is allowable. Because leakage at wellbores is not uniformly distributed, if leakage occurs, most leakage will occur in a relatively small subset of wellbores. Hence, actual allowable using CARB standards could be over an order of magnitude greater than 36 or 81 kg/d. Both of these rates are far higher than allowed for CO_2-equivalent rates for oil and gas wells being plugged for leakage of natural gas. There is no wording in the Class VI permit nor in the RDEIR that states that evidence of wellbore leakage (outside of injection wells) would trigger corrective action. Corrective action at legacy wellbores should be triggered for a leakage rate exceeding some pre-determined value regardless of whether overall leakage would ultimately result in less than 1% loss over a 100-year period. The California Air Resources Board should specify a maximum allowable CO_2 emission rate at a wellbore. Leakage could be quantitated using flux measurement developed by Kang et al (2016).

Wellbore schematics are absolutely vital in understanding the need or potential need for corrective action. 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 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, Colorado Energy & Carbon Management Commission). This unjustified lack of transparency can and indeed should erode public confidence in this project. It is difficult if not impossible for a third party to generate well diagrams and review internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc. for 354 wellbores during a public comment period. CTV should release wellbore schematics.

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. Findings in the Blade Energy Partners report confirms that statements stating that 0% of wellbores in the Area of Review require corrective action are untrue. Blade Energy Partners examined 31 cement bond variable density logs and determined that 3 wellbores (9.7%) require corrective action. This rate is more in line with published rates of wellbore failure rates ranging from 2 - 75% in the literature. Again, to more accurately determine the rate of wellbores requiring corrective, cement bond/variable density logging should be conducted in all wellbores. Also, pressure buildup in the annular space between surface and production casing should be evaluated. Pressure build-up in this annular space indicates well barrier failure.

In wellbore appendices for the 26R and A1 – A2 reservoirs, the term "adequate" with plugging and abandonments is vague and does not provide a measurable performance criteria per CEQA requirements. Importantly, per current CalGEM regulations, the term adequate should mean that cement is placed across the entire production interval and > 100 feet into the Reef Ridge Shale. If this is not the case, CalGEM should consider these plugs inadequate and consider replugging these wells.

In Volume II of the RDEIR (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. The word "adequate" is vague and does not provide a measurable performance criteria per CEQA requirements. CalGEM should ensure that annular cement extends completely through the A2 shale with integrity checked using a cement bond/variable density log.

The use of eddy covariance towers should be combined with wellbore monitoring supplemented with flux measurement using methods developed by Kang et al. (2016) and soil-gas monitoring using methods developed by DiGiulio et al. (2018).

For the project location, a peak ground acceleration rate of 0.4363g was estimated having a 5% probability of exceedance in 50 years for tectonic seismicity. This is approximately equivalent to a 9.8% probability of exceedance in 100 years. A further examination of the hazard curves indicates a peak ground acceleration of 0.3175g having a 10% probability of exceedance in 50 years and a 19% probability in 100 years. A near 20% probability of major ground shaking in the project area over the next 100 years (the time frame within CTV's responsibility or care) is concerning. CTV should specify and CARB should require a ground motion parameter such as peak ground acceleration within the Area of Review which would trigger an evaluation of wellbore integrity.

Since the probability of a major tectonic seismic event within a 100-year period is greater than 5% and the consequence of occurrence is potentially substantial, CARB should classify risk as high. Even if the consequence of the occurrence was classified as insubstantial, risk should be classified as medium not low or less than significant level as specified by CTV.

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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's Office of Research and Development. 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. I provide consulting services to states, federal agencies, and non-government organizations.

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

Journal Publications, Reports, Book Chapters, and Selected Presentations

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DiGiulio, D.C. **2023**. Chemical Characterization of Natural Gas Leaking from Abandoned Oil and Gas Wells in Western Pennsylvania. Presentation at PA League of Women Voters Shale and Public Health Conference. November 14, 2023, Pittsburgh, PA. https://www.shalepalwv.org/2023-shale-public-health-conference/

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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. https://www.sciencedirect.com/science/article/abs/pii/S0048969723055626

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Class II Disposal Wells

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ATTACHMENT B

Accufacts Inc.
"Clear Knowledge in the Over Information Age"

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October 15, 2024

Attn: Earthjustice
Michelle Ghafar
50 California Street, Suite 500
San Francisco, CA 94111

Re: Evaluation of Kern County Response to Comments and Final Recirculated Environmental Impact Report on the TerraVault I Carbon Capture and Storage Project.

Summary

I have reviewed the responses to comments recently presented by the Kern County Planning and Natural Resources Department and California Resources Corporation supporting the Recirculated Draft Environmental Impact Report ("RDEIR") for the above project.[1] The County's responses attempt to address the previous evaluations I submitted in support of comments on the project by the Center for Biological Diversity et al.

I find that the County's responses to comments, including the Cornerstone Engineering Report ("Cornerstone"), contain, at best, many misleading statements, and at worst, outright false statements concerning CO_2 liquid transmission pipelines for this project. For brevity, I will focus on three major deficiencies in the County's responses that, from my perspective and extensive experience, demonstrate the County and project proponent's lack of understanding and adequate analysis regarding CO_2 transmission pipelines and represent poor engineering practices for this project – a designation I do not use lightly. My discussion of these three major deficiencies also addresses the County's numerous falsehoods and attempts to misinform in its responses, especially in the references cited from Cornerstone. I focus on specific examples where the Kern County Planning Department and Cornerstone ("Commentors") have mischaracterized or misrepresented some of Accufacts' observations related to the RDEIR and this project:

1. The County's responses to comments gravely misrepresent the adequacy of current Federal minimum pipeline safety regulations regarding CO_2.
2. The County's responses to comments demonstrate that the County does not understand and has failed to properly assess liquid transmission pipeline rupture dynamics.
3. The County's responses to comments appear to misapply CO_2 vapor plume modeling approaches that are seriously incomplete, most likely negligent, and are not likely reflective of CO_2 liquid transmission pipeline rupture.

[1] Kern County Planning and Natural Resources Department ("Department") Final Recirculated Environmental Impact Report, "Chapter 7 Response to Comments Volume 3. SCH# 2022030180," August 2024, Section 4, (pages 7-29 – 7-34.), and Appendix A-4, "Cornerstone Engineering, Inc. Technical Report in Support of Response to Public Comments, August 2024.

I have seen these similar misrepresentations attempted in other states trying to rush multibillion dollar CO_2 pipeline project proposals. Such misrepresentations in CO_2 pipeline proposals in other states have been met with stark opposition as objective neutral scientific approaches uncover the many false representations by the project sponsors.

I note that this evaluation builds upon the points made in my prior reports on this project and incorporates by references those reports.

Focusing on the above main three findings in further detail:

1. **The Final REIR's attempts to convey that current Federal pipeline safety regulations are adequate are misleading and inaccurate.**

The Commentors' responses continuously overreach on stating or implying PHMSA's jurisdiction to regulate pipeline safety for this proposal. Such statements display a lack of understanding about pipeline safety regulatory history and development which is critical to hazardous liquid transmission pipeline operation and this project. For example, Commentors cite "This concentration meets the Pipeline and Hazardous Materials Safety Administration (PHMSA) standard for 'high purity' CO_2, i.e., CO_2 at a higher concentration than 90 %, which establishes federal regulatory jurisdiction."[2] On the same page they quote "RDEIR Vol. 2, Appendix B-4, CO2 Dispersion Modeling, states that dispersion models assume an operating temperature of 80 °F."[3] I need to point out that 80 °F is below the supercritical temperature of CO_2 which is 88 °F. At 80 °F, the fluid is liquid and not supercritical, <u>and not under the jurisdiction of PHMSA</u>. As a chemical engineer with over 50 years of experience, supercritical fluid requires the fluid to be both above the supercritical temperature and pressure (88 °F and 1070 psia for CO_2). The County's reference statement that "Supercritical fluid refers to a phase which occurs at high pressure **and/or** temperature and has physical properties intermediate between gas and liquid" is wrong -- another technical error that misleads decisionmakers and the public about regulatory oversight for this project.[4]

PHMSA can only enforce pipeline safety regulations as codified and, contrary to the County's repeated incorrect assertions, under current regulations this project could be exempted from PHMSA's jurisdiction. Thus, the County cannot rely on PHMSA's regulations to address project impacts.

In addition, the County goes on to state: "If future regulatory changes adopted by PHMSA or OSFM are applicable to project operations, compliance will be required [by] those agencies."[5] This is an erroneous statement demonstrating a lack of understanding in pipeline safety regulations, their development, and enforcement. Under the USC Code of federal regulations

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[2] Kern County Planning and Natural Resources Department ("Department") Final Recirculated Environmental Impact Report, "Chapter 7 Response to Comments Volume 3. SCH# 2022030180," August 2024, Section 4, page 7-30.
[3] *Ibid.*
[4] *Ibid* (emphasis added).
[5] *Ibid.,* p. 7-33.

enacted by Congress that establishes requirements for PHMSA to enact more specific pipeline safety regulations at the Federal level, § 60104. Requirement and limitations, (b) states:

> NONAPPLICATION. – A design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted.

New pipeline safety standards cannot be imposed on an existing pipeline facility which includes transmission pipelines like in this project. The statement made in the County's Response to Comments is in error and misleading.

2. **The responses to comments by Kern County and Cornerstone indicate they do not understand liquid transmission pipeline rupture dynamics and mainline valve effectiveness, which infects their whole pipeline safety analysis.**

Various citations in the Cornerstone Report and in Kern County's responses to comments related to the Final REIR clearly indicate to me the Commentors do not understand transmission pipeline release dynamics, especially during a pipeline rupture. This is an important concept to understand because pressure drop – which is the detection technique relied on by the County – is not the quickest nor most reliable method of transmission pipeline rupture remote detection. Because of the uniqueness of liquid transmission pipelines, especially CO_2, by the time a pressure loss indication reaches a remote sensor and gets to a remote control room, many hundreds, if not thousands, of tons of CO_2 have already been released out a rupture before mainline valves are closed. Anyone familiar with hazardous liquid transmission pipeline rupture dynamics should be easily able to demonstrate that pressure loss is a poor timely indictor that a rupture has occurred. History has repeatedly demonstrated that pressure loss is a poor timely indicator of transmission pipeline rupture. It is especially challenging for CO_2 pipelines that undergo significant and varying phase changes unique to carbon dioxide, which would be the case for this project.

I also need to clearly document misrepresentations and misstatements by Kern County and Cornerstone regarding the effectiveness of the California Office of Pipeline Safety and Kern County Fire Department's possible mitigation measures concerning CO_2 pipeline safety. For example, the County implies that more mainline valves, such as every mile along the pipeline, are effective for addressing pipeline ruptures. While I appreciate the attempt, these agencies' role, their authority in a pipeline failure, especially in a pipeline rupture, is limited. PHMSA's regulations say clearly such agencies are to maintain liaisons with the pipeline operator to the project, but actual control during a release event is very clear on this matter. Under PHMSA regulations the responsibility during a pipeline release rests with the pipeline operator who is supposed to know more about their pipeline than other parties that may be involved for many sound reasons. Spacing remote mainline valves every 1 mile on a 16-inch CO_2 liquid transmission pipeline – as proposed here with this project – may be the most dangerous of all safety attempts, creating the false illusion of a safety associated with mainline valves. The County must reassess this measure.

3. **Modeling approaches attempting to capture areas affected by CO_2 releases are seriously incomplete.**

Modeling approaches to better understand CO_2 plume release possible impact areas fall into two major categories: 1) Dispersion models and 2) Computational Fluid Dynamic ("CFD") model approaches. Dispersion modeling includes a wide range of approaches, many **not** suitable for heavier than air CO_2 plume predictions, especially if they do not prudently capture terrain impacts for heavier than air CO_2 vapor clouds involving transmission pipeline ruptures. CFD approaches have the advantage of having the ability to better capture terrain impacts. An excellent series of four articles by Paul Blackburn provides a simple layman's factual perspective on CO_2 plume release approaches and modeling efforts related to pipelines, especially in the more complex terrain associated with the Elk Hills field and surrounding areas that might be impacted by a CO_2 pipeline release.[6] Lack of prudent terrain discussion related to this proposal raises serious questions as to why CFD have not been incorporated into this project.

I find especially disturbing Kern County and Cornerstone comments that "Based on the modeling analysis in Appendix B-4, the RDEIR disclosed that the worst-case event for a catastrophic failure would result in a CO_2 dispersion for a range of 867 feet even in high winds."[7] This recklessly low estimate suggests a different modeling approach is warranted and smacks of the malfeasance demonstrated by the pipeline operator that caused the Satartia, MS pipeline rupture in February 2020. Commentors' observations related to the Satartia rupture appear to minimize the fact that while no one died, many people, including first responders, almost died. This citation illustrates to me a complete lack of understanding about what a transmission pipeline "worst case" release really is, especially for a 16-inch diameter CO_2 pipeline that forms a heavier than air vapor cloud that could travel large distances. Topography plays a controlling role in heavier than air CO_2 vapor releases given the tonnage of material that is released in transmission pipeline ruptures. Topography is not adequately presented in the County's Dispersion modeling efforts. I have seen this incomplete and poor modeling approach attempt in other CO_2 project proposals in other states that led to poor outcomes for the public and the pipeline operator itself, who eventually was required to more publicly demonstrate/defend their deficient model approaches and findings, much to their embarrassment. Failure to adequately address local topography in heavier than air Dispersion modeling approaches, quite bluntly, based on my many pipeline rupture investigations, constitutes negligence. In discussing the Satartia rupture release, the County has also downplayed the seriousness of that release event, not even mentioning that first responders and many people caught in the CO_2 cloud that flowed many miles downhill from the pipeline almost died. If not for the quick thinking and experience of some of the first responders trying to figure out what was going on, many fatalities would have occurred.

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[6] For example see, Paul Blackburn, Bold Alliance, "A tale of Perfect Goose Eggs: CO2 Plume Computer Modeling Options," Sept 30, 2024, at: https://pipelinefighters.org/news/a-tale-of-perfect-goose-eggs-co2-plume-computer-modeling-options/.

[7] Kern County Planning and Natural Resources Department ("Department") Final Recirculated Environmental Impact Report, "Chapter 7 Response to Comments Volume 3. SCH# 2022030180," August 2024, Section 4, p 7-31.

Lastly, I need to comment on setback distances. The discussions from the County I have seen to date appear to apply arbitrary distances that may not be effective, especially if local topography has not been prudently included in modeling efforts and the County's overall decision to employ dispersion rather than CFD modeling is concerning. Setback distances, if proposed, need to consider: the local topography, the tonnage, and rate of release from a transmission pipeline rupture, and realistic times to close mainline valves, which do not stop the CO_2 release out of a rupture even when such valves are closed, given the tonnage of inventory in the pipeline and its phase. CO_2 transmission pipeline ruptures can release remarkably high tons of heavier than air CO_2 that can spread many miles in the wrong topography. If Dispersion models appear to convey that such deadly plumes are measured in feet, the modeling approach is most likely incomplete and deficient.

Conclusions

From the above discussions it is clear the RDEIR and Final REIR for the project is far from adequate, or even complete, on many fronts. This raises many questions with the public as to why specific technical concerns have not been properly addressed at this late stage of project review.

Lastly, while not a specific pipeline associated matter, I have an ethical responsibility to note that the RDEIR still does not prudently address the possibility of a CO_2 injection well blowout on any of the six proposed CO_2 injection wells. In late 2015, California experienced 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 and periodic testing 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. The tonnage of CO_2 released from a well blowout 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 supply of CO_2 in the reservoir, easily surpassing pipeline rupture releases. Modeling would be useful, as the release distances will be many miles that will pale in comparison to the Aliso Canyon methane reservoir blowout. The County's responses to comments related to this issue in Section GR-71, Risk of Injection Well Blow, still fail to adequately or prudently address this threat.[8]

The responses by Cornerstone to somehow try to dismiss this concern by arguing that the Aliso Canyon blowout release is different misses the point. A release from an underground reservoir with essentially infinite inventory of heavier than air CO_2 needs to be more openly discussed and assessed. A simple discussion presenting how more than one level of independent

[8] *Ibid.,* p 7-71.

protection is incorporated to avoid release from an injection well and reservoir to avoid a blowout situation is needed. This is especially important given new evidence that some early CO_2 sequestration wells are experiencing CO_2 releases associated apparently with highly aggressive carbonic acid attack on specialized chromium carbon steel components utilized in such wells to attempt to avoid corrosion attack.[9] It is worth noting that such highly specialized steels are not utilized in transmission pipelines, but CO_2 sequestration well makeup and levels of independent safety needs to be explored.

Richard Kuprewicz

Richard B. Kuprewicz,
President,
Accufacts Inc.

[9] Annie Snider, Ben Lefebvre, Energywire, "Carbon storage projects hit a hurdle: Corroding steel," Oct 9, 2024.

Attachment A
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.