Evaluation of Draft Environmental Impact Report on Geological Storage of Carbon Dioxide at the Carbon TerraVault I Facility in Kern County, California

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February 25, 2024

About the Author: Dr. DiGiulio is a retired geoscientist from the U.S. Environmental Protection Agency's Office of Research and Development. He has conducted research on: emissions of volatile organic compounds from abandoned wells, leakage of produced water, condensate, and drilling fluids from impoundments to groundwater, contamination of groundwater from hydraulic fracturing, subsurface methane and carbon dioxide migration (stray gas), intrusion of subsurface vapors into indoor air (vapor intrusion), gas flow-based subsurface remediation (soil vacuum extraction, bioventing), groundwater sampling methodology, soil-gas sampling methodology, gas permeability testing, and solute transport of contaminants in soil. He assisted in the development of EPA's original guidance on vapor intrusion and the EPA's Class VI Rule on geologic sequestration of carbon dioxide (Tier II Committee). He has served as an expert witness in litigation relevant to oil and gas development, testified before State oil and gas commissions on proposed regulation, and testified before Congress on the impact of oil and gas development on water resources. His consulting services to non-government organizations have included reports on: stray methane gas migration, geological carbon storage in Louisiana, storage of natural gas liquids in solution mined caverns, proposed oil and gas regulations in Colorado, impact to groundwater resources from Class II disposal wells in Ohio, Idaho, and Florida, produced water transport in barges along the Ohio River, proposed EPA regulation on discharge of produced water to surface water, and Bureau of Land Management leases in Wyoming, Montana, and Colorado.

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Background

A Draft Environmental Impact Report (DEIR) was prepared by Kern County as the Lead Agency under the California Environmental Quality Act (CEQA). In volume 1 of the DEIR, it is stated that Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of the California Resources Corporation, proposes to inject supercritical carbon dioxide (CO_2) at two locations (26R and A1-A2 reservoirs) in the Monterey Formation at the Elk Hills Oil Field in Kern County, California (DEIR, 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 (DEIR, 2024a). Currently, the Elk Hills Power Plant provides electricity for both oilfield operations and the California wide power system (DEIR, 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 (DEIR, 2024a). Turbidite deposited sands are interbedded with siliceous shale. Sand porosity and permeability averages 25% and 45 millidarcy (mD), respectively (DEIR, 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 (DEIR, 2024b).

The 26R reservoir was discovered in the 1940s while the A1-A2 reservoir was discovered in the 1970s (DEIR, 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 (DEIR, 2024b).

The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for both the 26R and A1-A2 reservoirs (DEIR, 2024a). The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and clay beds. The Reef Ridge Shale is continuous and ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity (DEIR, 2024b). To date, over 7,500 wells have been drilled to various depths within the Elk Hills Oil Field (DEIR, 2024b). There are numerous well penetrations in the Monterey Formation outside the 26R and A1 – A2 storage areas as illustrated in figures in Volume 2 of the DEIR. The DEIR fails to specify the exact number of well penetrations.

At full operation, the project is designed to inject up to 1.46 million tons of CO_2 per year into the 26R reservoir (up to 26 years) and up to 0.75 million tons per year in the A1-A2 reservoir, for a total capacity of 2.21 million tons per year (DEIR, 2024a). Additionally, 10 existing wells will be converted to monitoring wells, and six existing wells would be converted into seismic monitoring wells (DEIR, 2024a).

Setbacks and Encroachment

Leakage of CO_2 from wellbores is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2 (Jordan and Benson, 2009, Zhang and Bachu, 2011). There is interest in using depleted oil and gas reservoirs for geological storage of CO_2 due to extensive preexisting geological characterization and infrastructure but the presence of a large number of well penetrations increases the possibility of leakage (Celia et al., 2005).

From a health and safety perspective, if large-scale leakage were to occur at the surface, asphyxiation and suffocation are of concern. Continued exposure to CO_2 concentrations above 20–30% is associated with suffocation to humans and most air-breathing animals (Damen et al., 2006). Since CO_2 is denser than air, topography and prevailing meteorologic conditions would largely govern risk from a large-scale release with gas buildup being greater in valleys and low-lying areas.

As discussed in Volume 2 of the DEIR (DEIR, 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 (DEIR, 2024b).

Probably the best-known anthropogenic release of CO_2 occurred in February 2020 from a CO_2 pipeline rupture in proximity to Satartia, MS. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld (DEIR, 2024b). Pipeline operators are required to establish atmospheric models to prepare for emergencies. Denbury's model did not contemplate a release that could affect the Village of Satartia (DEIR, 2024b). Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions (DEIR, 2024b). Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release (DEIR, 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 (DEIR, 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 (DEIR, 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 (DEIR, 2024b).

A clearly unacceptable release from a wellbore would be a CO_2 well blowout. A CO_2 well blowout is considered a low probability high consequence incident (Oldenburg and Budnitz, 2016) that could cause an immediate danger to public health in the vicinity of an abandoned well. The Sheep Mountain CO_2 blowout in March 1982 is a well-documented case in the literature (GEM Wiki, 2024). The leakage rate was estimated to be 13,000 metric tons CO_2 per day (GEM Wiki, 2024). 100% CO_2 flow was observed in the well with chunks of dry ice occasionally ejected hundreds of feet into the air. Other examples of CO_2 well blowouts include the Travale geothermal field, Italy in 1972 having a CO_2 release rate of 113 kg/s and the Torre Alfina geothermal field, Italy in 1973 (Lewicki et al., 2007) having a CO_2 leakage release rate of 76 kg/s (Lewicki et al., 2007; Aines et al., 2009).

Another example of CO_2 release via a wellbore is Crystal Geyser in Utah (the largest cold geyser in the world). The geyser was unintentionally created in the 1930s after a prospective oil well was drilled about 2,600-foot-deep into a fault zone above a natural CO_2 reservoir (DEIR, 2024b). Shortly after drilling, the well was improperly abandoned allowing CO_2 to be released through the well (DEIR, 2024b). Crystal Geyser eruptions last from 7 to 98 minutes with a release rate between 2.5 and 6 kg/s. Downwind CO_2 concentrations have been measured during eruptions, averaging about 4,000 parts per million (ppm) (0.4 percent) at 160 feet, and 800 ppm at 330 feet (DEIR, 2024b).

In 2011, an improperly plugged and abandoned well failed at the Tinsley Field, Mississippi during CO_2 enhanced oil recovery (EOR) (DEIR, 2024b). There were incomplete records of abandoned wells at the site (DEIR, 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 (DEIR, 2024b). In 2013, an underground CO_2 blowout occurred at the CO_2-EOR Delhi field in Louisiana, when two or more plugged and abandoned wells failed underground (DEIR, 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 (DEIR, 2024b).

Comment: As evidenced in the Satartia, MS CO_2 pipeline release and other documented incidences of CO_2 release, including those from wellbores, release of CO_2 from an injection well or failed plugged or unplugged wellbores could be catastrophic depending on surface topography and meteorologic conditions. The closest sensitive receptor to the project site is McKittrick Elementary School, which is 2.5 miles southwest of the facility pipeline and 4.46 miles from injection well 357-7R. The nearest residence is approximately 4.5 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 (DEIR, 2024a). Based on project-specific and site-specific considerations, the County should determine safe distance(s) for injection wells, wellbores, and pipelines from human receptors and adopt setback(s) that prohibit development at unsafe distance(s).

Comment: Another issue of concern is future development encroaching near land used for CO_2 storage. The land area containing wellbores and vicinity of this land area (e.g., within 1 mile) could conceivably not be suitable for public use for hundreds of years. The DEIR does not address whether or how land uses on surrounding properties might change (soon or in the long term) in ways that would increase the dangers posed by the project.

Mineralization of Injected CO_2

CTV states that full mineralization of CO_2 is expected to occur in two to five years (DEIR, 2024a) - 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. As correctly stated in the Class VI permit applications (EPA, 2024), 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 extremely 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 for Terravault (EPA, 2024).

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 (EPA, 2024). 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 storage area, CTV states that because of low water saturation within the Monterey Formation A1 - A2 storage reservoir results in greater than 98% of the CO_2 injectate remaining supercritical phase, minimizing the quantity of CO_2 dissolving in formation water through time (DEIR, 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: Assessment of mineralization of injected CO_2 in Volume 1 of the DEIR is incorrect and contradicts Volume 2 of the DEIR and the Class VI permit applications. Mineralization of CO_2 is not expected to occur to any appreciable degree during storage in the 26R and A1 – A2 storage reservoirs. The DEIR must be updated to reflect an accurate assessment of mineralization and the additional potential impacts of CO_2 storage in a supercritical state. Also, less storage in water and oil than expected would result in a more rapid pressure increase than expected and necessitate updating computational modeling before the mandatory five-year reevaluation period.

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 (DEIR, 2024b). With increasing depth, the structure subdivides into three distinct anticlines, separated at depth by inactive high-angle reverse faults (DEIR, 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 (DEIR, 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 (DEIR, 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 (DEIR, 2024a).

Comment: CTV states that the Monterey Formation in the A1-A2 storage reservoir has "*minimal*" connection outside the Area of Review (DEIR, 2024b). The DEIR is vague about what this means for the project. Do anticlinal structures provide full containment or not? The Monterey Formation A1-A2 CO_2 sequestration reservoir is located in the Northwest Stevens anticline. As discussed by Zumberge et al. (2005), the Northwest Stevens anticline and the western 29R structure share some of the same turbidite sand bodies. Sandstone reservoirs on the two structures also share the same oil family. After filling of the Northwest Stevens anticline reservoirs, oil appears to have spilled into and filled the 24Z trap. 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, again moving within turbidite sand bodies from the Northwest Stevens structure. It appears then that there is hydraulic communication between the Monterey Formation inside and outside of the 26R and A1 - A2 storage areas and injection must be carefully managed to avoid migration of injected CO_2 outside of these storage areas (exceedance of spill point). From schematics provided by CTV (DEIR, 2024b), there are a large number of wellbores screened in the Monterey

Formation outside of storage areas. At least some of these wellbores should be converted to monitoring wells to monitor for both pressure perturbation and CO_2 leakage during injection.

Comment: 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 (DEIR, 2024a). 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 (DEIR, 2024b). However, as discussed in the previous comment, this geochemical analysis also confirmed migration of oil between anticlinal traps, which the DEIR does not disclose. More importantly, there is no discussion of how 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, until CRC or CTV provides sufficient documentation, the veracity of these claims cannot be independently evaluated. CTV should provide evidence for claims of full confinement during injection. As previously discussed, CTV should convert several existing oil and gas wells screened in the Monterey Formation outside storage reservoirs into additional monitoring wells.

Permanence Criteria and Monitoring Plan

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% per thousand years is necessary for geological storage of CO_2 to achieve the same climate benefits as renewable energy sources (Shaffer, 2010). 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 1000 years. Leak rates of 0.01% per year, equivalent to 99% retention of the stored CO2 after 100 years, may be adequate to ensure the effectiveness of CO_2 storage (Hepple and Benson, 2005). As part of an application for Sequestration Site Certification, 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). There are no storage effectiveness criteria in the Class VI federal regulations. This is a major regulatory deficiency that now must be resolved on a state-by-state level.

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 state that well densities of 8 wells/km^2 are of concern. 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 through the confining layer and a storage area of 5332 acres (21.58 km^2), a well penetration density of 16.4 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.

Comment: Information presented in the DEIR and Class VI permit applications does not support a finding that the project will retain 99% of stored CO_2 in excess of 100 years at cessation of injection, as required by the California Air Resources Board. Such a retention finding is 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 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.

Comment: In 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 (DEIR, 2024a). In mitigation measure MM 4.8-1 it is stated that, "*Prior to any injection of CO2 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*" (DEIR, 2024a). The monitoring plan submitted in the Class VI permit applications and attached in Volume 2 of the DEIR does not directly consider leakage from well penetrations – the most likely source of loss of retention of CO_2. Hence, MM 4.8-1 is deficient and should be rejected. It will be necessary to combine continuous areal monitoring of leakage with periodic monitoring of individual well penetrations to ensure retention of CO_2 and to quantify leakage.

Use of 10% per Year Pressure Loss as a Leakage Verification Criterion

CTV states that in the 26R reservoir, starting in 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting reservoir pressure. Since blow-down, reservoir gas pressure has remained at 150-300 psig. At the 26R Reservoir, maximum allowable downhole pressure will vary from 3847 to 4294 psig with planned bottomhole injection pressure between 3558 to 4060 psig. The initial discovery pressure was 3,250 psig (DEIR, 2024b).

Comment: CTV states 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 (DEIR, 2024b). In the A1 - A2 Storage Area, CTV states that pressure at the injection wells are expected to stabilize within one year after injection ceases and that final pressure will target the initial reservoir pressure at the time of discovery (DEIR, 2024b). Again, CTV states that monitoring data will be reviewed to ensure that the CO_2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year) (DEIR, 2024b). CTV states that pressure stabilization will be used for non-endangerment assessment (DEIR, 2024b). There does not appear to be any corresponding discussion of a 10% per year pressure loss criterion for leakage verification in the Class VI permit applications. A simple back of the envelope calculation indicates 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 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). Nevertheless, this metric of leakage verification is not sufficiently sensitive to be of practical use and should be reexamined if not rejected for both the 26R and A1 - A2 storage areas.

Wellbore Abandonment Evaluation to Support Plugging

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 continue to leak gas after plugging. Kang et al. (2016, 2017) and DiGiulio et al. (2023) found mean emission rates of leakage of methane from plugged wells in western Pennsylvania were 360 and 390 g/d, respectively. However, the computation of the mean emission rate from plugged wells in the dataset from DiGiulio et al. (2023) excluded an outlier, a plugged well leaking at a rate of 83 kg/d. It is important to realize that these rates are from depleted oil and gas fields. Higher emission rates of gas (in this case CO_2) would be expected if reservoirs were repressurized as is the case for geological storage of CO_2 in depleted oil and gas fields such as at the TerraVault I Project. 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 that leakage of CO_2 from abandoned wells would follow a similar distribution.

Wellbore integrity failure is not uncommon. 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. Gas migration and surface casing vent flows require wellbore treatments such as cement squeezes and casing repair (Hachem et al., 2023; Ingraffea et al., 2014; Yousuf et al., 2021). The process of remediating subsurface leakage is typically more complex and expensive than the average plugging procedure (Raimi et al., 2021) but must be addressed prior to plugging. Once plugged, subsurface leakage via the annulus may go unchecked leading to persistent groundwater impacts and emissions to the atmosphere.

As stated in the Class VI permit applications, 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 Reservoir, 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 or to the surface.

Within the Area of Review the owners or operators must identify all potential conduits for fluid movement out of the injection zone, including both geologic features and artificial penetrations (40 CFR 146.84(c)(1)(iii)). The owner or operator must then evaluate artificial penetrations that may penetrate the confining layer(s) of the injection project for the quality of casing and cementing, and in the case of abandoned wells, for the quality of plugging and abandonment, and perform corrective action on any identified artificial penetrations that could serve as a conduit for fluid movement (40 CFR 146.84(c)(2), 146.84(c)(3), and 146.84(d)).

In its guidance document on Area of Review and Corrective Action, EPA emphasizes the need for a robust evaluation of both plugged and unplugged wellbores that penetrate the primary confining layer (EPA, 2013). EPA provides an extensive set of recommendations and guidelines for evaluation of artificial penetrations (EPA, 2013). 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). Information should also 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.

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 required (EPA, 2013). Additional testing could include multi-finger caliper logging, cement evaluation logging, internal and external mechanical integrity testing similar to that conducted on injection wells, and sidewall coring (EPA, 2013).

EPA also states that after all the available records have been reviewed, any wells located within the Area of Review that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging, as required in the Class VI Rule (40 CFR 146.84(c)(3)) (EPA, 2013).

Comment: In the Class VI permit applications for the 26R Reservoir Area, CTV identified 204 wellbores that penetrate the Reef Ridge Shale. CTV states that three wells will be repurposed as monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injection well. CRC states that it has identified 157 wellbores that require plugging because the wellbores will not be used for injection or monitoring. Of the remaining 200 wellbores, 35 wellbores have been plugged back for sidetrack and have API-12 status for plugging and abandonment. No wellbores in the 26R Reservoir area have been permanently plugged back to surface. The disposition of the other 8 wellbores is unclear. It is also unclear why all 200 unused wellbores will not be plugged back to the surface prior to injection. In the DEIR, CRC states that 36 wellbores have been plugged back for sidetrack, leaving 164 wellbores that require standard plugging procedures. Discrepancies in the number of wellbores requiring plugging between the Class VI permit applications and the DEIR need to be resolved.

Comment: In the DEIR, CTV states that 33 wells in the A1-A2 have been identified for abandonment. The DEIR must disclose the disposition of the other 78 unplugged wellbores, and the plan to plug back to the surface those wells that will not be used for injection or monitoring.

Comment: In Attachment B of Volume 2 of the DEIR, CTV identified 204 wellbores in the 26R reservoir and 150 wellbores in the A1 - A2 reservoirs that penetrate the Reef Ridge Shale - the primary confining layer in both storage areas. For the 26R Reservoir area, CTV states that "*Appendix 1*" lists the wells individually and provides information including well name, API-12, well type, status, spud date, surface coordinates, and pre-operational requirements. Despite several references throughout the DEIR, the DEIR fails to include Appendix 1 itself. In addition, there is no mention of preparation of the same type of Appendix for the A1 – A2 Reservoir area. A detailed wellbore-by-wellbore evaluation for both reservoirs will be necessary to assess wellbore integrity issues prior to plugging to plug wells in a manner to minimize leakage to the extent possible.

Comment: Class VI permit applications require "A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include 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" (§146.82(a)(4)). In the Class VI permit applications, CTV states that an appendix entitled "*Well Table with Corrective Action Assessment*" lists the wells individually and provides a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion. This table also purportedly identifies pre-operational requirements and the corrective action assessment for each wellbore. Despite explicitly being required in the Class VI permit applications, the appendix with tabulation of wells with the Area of Review was not added to EPA's Class VI docket until 2/7/2024. In addition, the provided appendix is still missing critical information and riddled with vague and indefinite terms. For example, in its tabulation, records of plugging and/or completion only consist of dates. Records of plugging and/or completion should at least include wellbore schematics including actual details of plugging and completion. The table also repeatedly evaluates the annular isolation within the upper confining later as "*adequate*" which fails to provide any meaningful criteria or performance standards. Information submitted in this regard by CTV is insufficient and does not appear to be in compliance with §146.82(a)(4).

Moreover, inclusion of what appears to be part of the DEIR's missing Appendix 1 in EPA's Class VI docket does not absolve Kern County from its own obligation to include the full Appendix with the DEIR for public review and comment, and to use it to inform its own analysis of impacts and appropriate mitigation for the CTV 1 project. The failure of the DEIR to include the Appendix means the DEIR must be recirculated with the missing information included. CTV should submit all information associated with wellbores relevant to wellbore integrity (e.g., internal and external mechanical integrity tests, drilling and cementing records, cement bond/variable density logs, cement squeeze operations, etc.).

Comment: In the Class VI permit application for the 26R Reservoir, CTV states that it accessed internal databases as well as California Geologic Energy Management Division information to identify and confirm wells within the Area of Review (EPA, 2024). CTV states that the corrective action assessment included the generation and detailed review of wellbore/casing diagrams for each well in the Area of

Review (EPA, 2024). Information used in the review included 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 (EPA, 2024). Perforated intervals are described with depth and status of perforations. Top of cement determination supported the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone were reviewed for both measured and true vertical depths (EPA, 2024). 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 (EPA, 2024). All of this information is missing in the DEIR. This information (wellbore diagrams, cement evaluation logs, internal and external mechanical integrity tests, etc.) should immediately be made available to the public. This information is critical in determining the retention of CO_2 in storage reservoirs. A detailed wellbore-by-wellbore evaluation is necessary to assess wellbore integrity issues prior to plugging in order to plug wells in a manner that minimizes leakage to the extent possible.

Comment: In the DEIR, CTV identified 204 wellbores in the 26R reservoir and 150 wellbores in the A1-A1 reservoirs (DEIR, 2024b). No wellbores were deemed deficient in either reservoir and none require corrective action. This is a 0.0% wellbore barrier failure rate for 354 wellbores, 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 degree of skepticism. It does not appear that EPA conducted an independent evaluation of wellbore integrity of well penetrations. It is both inappropriate and negligent to simply accept a statement of no wellbore barrier failure without supporting information. Again, all supporting information (wellbore diagrams, cement evaluation logs, internal and external mechanical integrity tests, etc.) should immediately be made available to the public to enable an independent evaluation of wellbore integrity.

Comment: In the Corrective Action Plan (EPA 2024), CTV states that all wellbores within the Area of Review will, "*if necessary*", be pressure tested prior to abandonment and monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, "*if conditions allow*". It is unclear as to what conditions would preclude pressure testing. What is a demonstration of adequate zonal confinement? These statements are far too vague to be of any use. Hence, this 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. Since all wellbores penetrating the confining layer will be in direct contact with supercritical CO_2 at high pressure, internal (pressure) and external (e.g., temperature, noise, oxygen-activation logging) mechanical integrity tests should logically be conducted on these wellbores prior to plugging and abandonment, similar to regulatory requirements for plugging injection wells.

Comment: In the A1-A2 area, CTV states that it assessed USDW protection using the following criteria: (1) surface or intermediate casing over the USDW; (2) if the well is abandoned, a cement plug across base of USDW; and (3) cement in the annulus in intermediate casing above the surface casing shoe and "*sufficient*" annular cement within the confining Reef Ridge Shale. Since all wellbores will be exposed to supercritical CO_2 for presumably thousands of years at high pressure in both the 26R and A1-A2 reservoirs, it is critical that existing wellbores not being used for injection or monitoring be plugged in a manner consistent with regulatory requirements for plugging injection wells (4 plugs). As per Class VI regulations, all well penetrations should include a cement plug through the primary confining zone, and/or across the injection zone/confining zone contact, with sufficient integrity to contain separate-phase carbon dioxide and elevated pressures. Cement plugs should also be located across the bottom of any casings and at the base of the lowermost USDW. A surface plug would also typically be required by local well abandonment regulations to ensure that there is no risk of anyone physically falling into the well bore. Materials that are compatible with CO_2 must be used where appropriate (40 CFR 146.84(d)). A wall-to-wall barrier throughout the confining layer is critical to zonal isolation of CO_2. If well casing is not removed prior to plugging, the integrity of annular cement must be verified through the use of external mechanical tests and recent cement evaluation logs.

Comment: As stated in the Class VI applications, the Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare Formation, is continuous across the Area of Review, and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin will be monitored continuously for pressure and temperature changes at one monitoring well in the 26R Reservoir. The DEIR does not adequately explain why there is only one monitoring well in Etchegoin. What is the minimum magnitude of leakage that would be detected from pressure perturbation from the injection well located at the greatest distance from the monitoring well? The permittee needs to evaluate this to justify the existence of only one monitoring well in the Etchegoin Formation.

Comment: In the Class VI permit applications, CTV states that surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines, will be conducted using eddy covariance towers (DEIR, 2024b). In regard to leakage to the atmosphere, under 40 CFR Part 98 Subpart RR, an operator must submit a proposed monitoring, reporting, and verification (MRV) plan to EPA within 180 days of receiving a final Class VI permit (§98.448(b)(2)). As part of the MRV plan, the operator must: (1) "identify potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways" (§98.448(b)(2)); (2) develop "a strategy for detecting and quantifying any surface leakage of CO_2" (§98.448(b)(3)); and (3) develop "a strategy for establishing the expected baselines for monitoring CO_2 surface leakage" (§98.448(b)(4)). Hence, leakage to the atmosphere will be considered at some point. However, a monitoring program should be specific to evaluating leakage from plugged well penetrations as general air monitoring may not be sufficiently sensitive to determine leakage. MM 4.8-1 needs to include specific monitoring for leakage from plugged and unplugged well penetrations. Methods employed by Kang et al. (2016) can be used for CO_2 monitoring at both plugged and unplugged wells.

Seismic Risk Evaluation

Of particular concern at the TerraVault I project is the effect of natural or induced seismicity on wellbores. After a well is permanently plugged and abandoned, natural or induced seismicity can damage wellbores. For example, hundreds of oil well casings were sheared in the Wilmington oil field in Los Angeles during five or six earthquakes of relatively low seismic moment magnitude (**M** 2 to **M** 4) during a period of maximum subsidence in the 1950s (Dusseault et al., 2001). The seismic moment magnitude is the product of the area of rupture, the average displacement on the fault (a fracture or zone of fracture between two blocks of rock), and the shear modulus, a parameter related to the rigidity of rocks in the fault zone measured on a logarithmic scale (GWPC, 2021). Recently, Pozzobon et al. (2023) documented increased leakage of gas from plugged oil and gas wells resulting from seismic activity due to injection of produced water into disposal wells and hydraulic fracturing.

Impacts of earthquakes on buildings and pipelines, including those that are buried, have long been an active area of civil engineering research. There are empirical estimates of pipeline damage that relate the number of repairs to peak ground acceleration, peak ground velocity, maximum ground strain, and other factors. There is a need to extend this existing body of research to subsurface wellbore leakage caused by earthquakes (Kang et al., 2019). Hence, seismic monitoring and hazard assessment should be based not only on the magnitude of seismic event but on ground motion.

USEPA's Class VI regulations require permit applicants to provide a determination that seismic activity will not compromise subsurface containment of injected carbon dioxide (40 CFR 146.82(a)(3)(v)). The Class VI rule provisions do not address potential damage to buildings and infrastructure (including wellbore cement sheaths of active and abandoned wells) associated with geologic storage of CO_2. However, as part of its permanence requirements for geologic sequestration, the California Air Resources Board (CARB) has developed requirements which include consideration of natural and induced seismicity (CARB, 2018). In the California Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CARB, 2018), if an earthquake of $\mathbf{M} \geq 2.7$ is detected within a radius of one mile of CO_2 injection operations, a determination must be made whether the mechanical integrity of any well, facility, or pipeline within this radius has been compromised. This protocol however does not consider a naturally occurring major seismic event at distance from an injection well which could induce ground movement damaging wellbores. In addition, the California Energy Commission has developed guidelines to evaluate the potential for induced seismicity during geological storage of CO_2 (CEC, 2017).

Given uncertainty in potential impact due to natural and induced seismicity during geological storage of CO_2, protocols developed by U.S. Department of Energy's (DOE) Recommended Practices for Managing Induced Seismicity Risk Associated with Geologic Carbon Storage (Templeton et al., 2021, 2023) should be used when permitting a facility for geological storage of CO_2. This integrated and risk-based protocol is a product of the DOE's National Risk Assessment Partnership, a multi-year collaborative research effort of Los Alamos National Laboratory, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, National Energy Technology Laboratory, and Pacific Northwest National Laboratory. This protocol specifically addresses the risk of seismicity at a geologic carbon storage facility and is relevant to CO_2 injection at Carbon TerraVault I. Recommendations by Templeton et al. (2021, 2023) and regulatory requirements and guidelines by EPA and the State of California are used here as the basis of evaluation for the seismicity portion of the permit application.

<u>Review of Applicable Local, State, and Federal Laws and Requirements on Seismicity</u>

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 DEIR, the Carbon TerraVault I project does not appear to be within a Zone of Required Investigation. In the DEIR, Kern County reviewed compliance with other applicable laws and regulations for this project.

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 DEIR, Soils Engineering Inc. conducted a review of naturally occurring seismic events since 1852. Their identified Region of Concern however was limited to 100 km from the Carbon

TerraVault I project. Major faults within this area are illustrated in Figure 1. From 1852 through 2020, southern California has experienced at least 20 major earthquakes with estimated Richter scale magnitudes ranging from 5.9 to 8.0. As Soils Engineering Inc. discuss, the nearest major active faults in the western portion of the CTV Project are the San Andreas Fault located approximately 23.0 to 23.3 km to the southwest, the Kern Front Fault located approximately 39.7 to 39.9 km to the northeast, the Pleito Fault located approximately 48.3 to 48.7 km to the southeast, the White Fault located approximately 48.6 to 48.9 km to the east-southeast, and the Buena Vista Fault (minor active fault) located approximately 15.42 km to the southeast. The nearest major active faults in the eastern portion of the CTV Project are the San Andreas Fault located approximately 23.9 to 24.6 km to the southwest, the Kern Front Fault located approximately 35.5 to 36.8 km to the northeast, the White Fault located approximately 39.2 to 42.5 km to the east-southeast, the Pleito Fault located approximately 40.0 to 42.9 km southeast, and the Buena Vista Fault located approximately 9.41 km to the southeast.

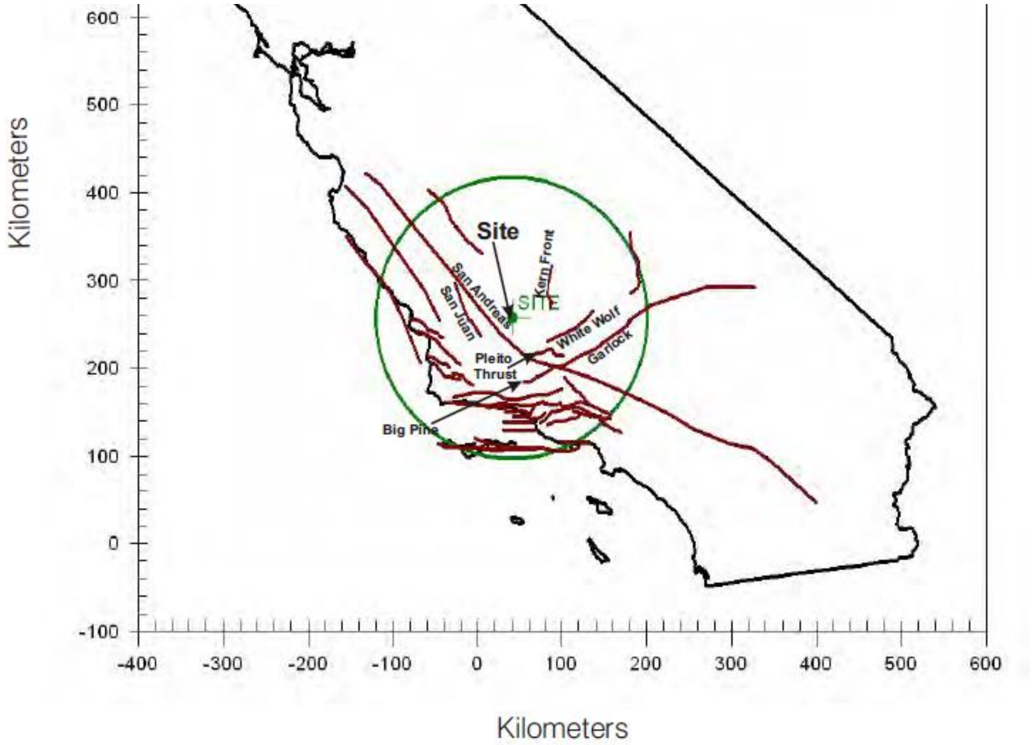


Figure 1. Identification of major faults in the vicinity of the TerraVault 1 Project. Figure from Soils Engineering, Inc. in Vol 2. of DEIR.

Some of these faults have produced earthquakes in excess of seismic moment magnitude **M** 7 (Figure 2). 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 3) 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 3, 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.

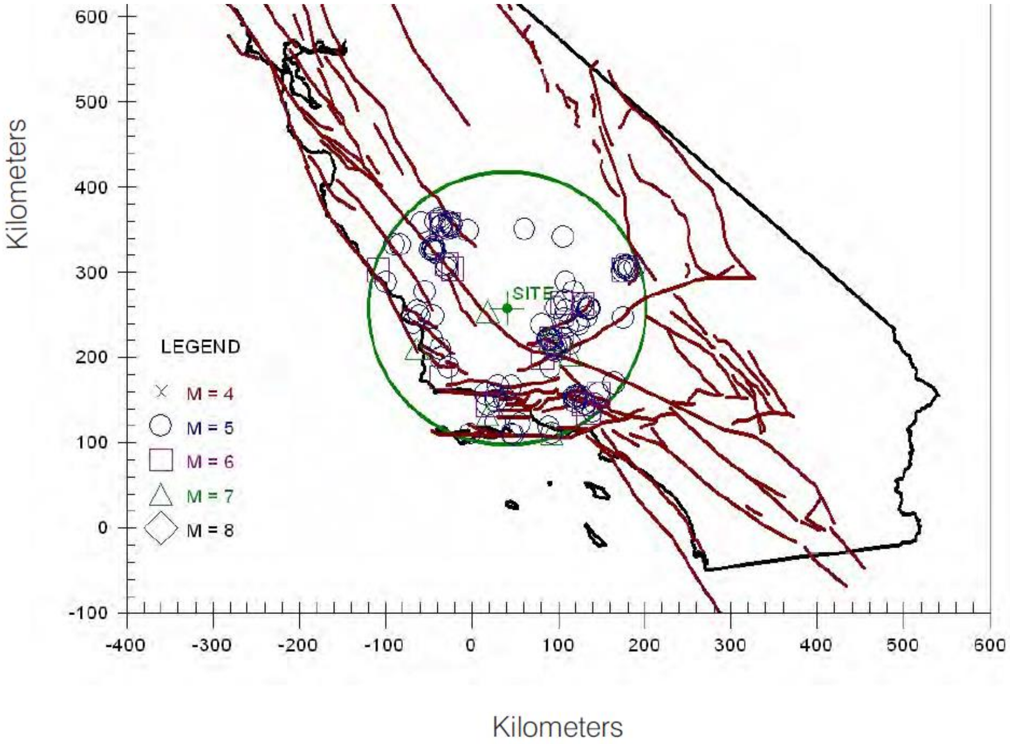


Figure 2. Magnitude of earthquakes along major faults in the vicinity of the CTV project. Figure from Soils Engineering, Inc. in Vol 2. of DEIR.

During the Fort Tejon earthquake, horizontal displacement as much as 9 meters was observed on the Carrizo Plain. As a result of the shaking, the current of the Kern River was turned upstream, and water ran four feet deep over its banks. The waters of Tulare Lake were thrown upon its shores, stranding fish miles from the original lake bed. The waters of the Mokelumne River were thrown upon its banks, reportedly leaving the bed dry in places. The Los Angeles River was reportedly flung out of its bed, too. Some of the artesian wells in Santa Clara Valley ceased to flow, and others increased in output. New springs were formed near Santa Barbara and San Fernando (USGS, 2023).

At the time of the earthquake, California was sparsely populated, especially in the regions of strongest shaking. Were the Fort Tejon shock to happen today, the damage would easily run into billions of dollars, and the loss of life would likely be substantial (USGS, 2023). Strong shaking was reported to have lasted for at least one minute but possibly lasted two or three minutes. The portion of the fault that ruptured in 1857 has settled into a period of dormancy and this has given rise to suggestions that future slip along that zone may be characterized by a very large 1857-type event followed by another period of inactivity (Sieh, 1978).

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).

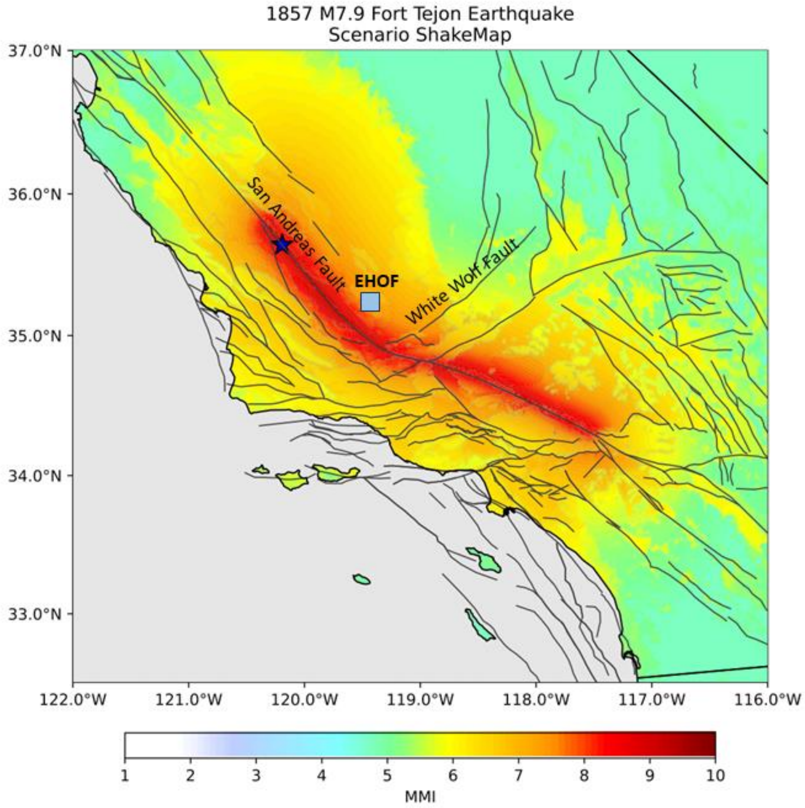


Figure 3. Location of faults in southern California and of the 1857 Tejon earthquake on the San Andreas Fault and estimated Modified Mercalli Intensity. The Epicenter illustrated by dark blue star. Approximate location of Elk Hills Oil Field (EHOF) illustrated by light blue box. San Andreas and White Wolf Faults identified. Figure modified from Southern California Earthquake Data Center.

As discussed by Soils Engineering, Inc. in Volume 2 of the DEIR, 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).

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.

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 code in the U.S. (International Building Code), the 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 requiring a determination of integrity of any well, facility, or pipeline when an earthquake of **M** ≥ 2.7 has been detected within a radius of one mile of CO_2 injection operations is reasonable.

Comment: CTV states that during the 1952 Kern County earthquake, there were no reservoir containment issues associated with oil and gas operations at the Elk Hills Oil Field. While the 26R reservoir was discovered in the 1940s, it is stated in Volume 2 of the DEIR that the Monterey Formation reservoir in the

26R anticline was not developed until 1970's. Also, the A1-A2 reservoir was not discovered until the 1970s. Hence, CTV's statement in this regard is misleading and should be removed from the DEIR.

Hazard Evaluation of Natural Seismic Events

Comment: Seismic risk is calculated from four main contributing factors. The first factor is seismic hazard, which is the probability of exceedance of a specified ground motion intensity. The second factor is exposure, which is the infrastructure or population potentially affected by seismicity. The third factor is fragility, which is the susceptibility of each element of exposure to damage from ground motion intensity. The fourth factor is consequence, which is the metric chosen to quantify the risk (e.g., economic impact, loss of CO_2 containment) (Mitchell and Green, 2017). The seismic risk analysis conducted in the DEIR is deficient because it fails to consider all four factors, especially for legacy wells which were not considered at all. In the DEIR, 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 DEIR.

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 2 of the DEIR contains a report entitled “Preliminary Soil and Geologic Evaluation Terra Vault 1 Carbon Capture Project Elk Hills” completed by Soil Engineering Inc. that contains a probabilistic seismic hazard analysis for the facility. Soils Engineering Inc. used the computer modeling program EQSEARCHWIN version 3.0 (Thomas Blake) to evaluate historical earthquakes in the area of the site over the last 200 years. The largest estimated site accelerations are 0.221g (Section 36) to 0.295g (Section 7/18) from a 7.9 magnitude earthquake on January 9, 1857.

A number of active faults are located within a 50-mile radius of the subject site. Soils Engineering Inc. used the computer modeling program EQFaultwin vers. 3.0 (Thomas Blake) to evaluate the effect that a major earthquake within a 50-mile radius might have on the site. The program computed the maximum peak site ground accelerations resulting from an earthquake. Results of this analysis are presented in Table 2.

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 magnitude 8.0 on the San Andreas Fault approximately 23 to 24.6 kilometers away. A maximum probable earthquake of magnitude 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 4. The USGS program calculates peak ground and spectral acceleration at a site for all the earthquake locations and magnitudes believed possible in the vicinity of the site. Each of these magnitude-location pairs is believed to happen at some average probability per year. Small ground motions are relatively likely, large ground motions are very unlikely. Beginning with the largest ground motions and proceeding to smaller, probabilities are summed to calculate a total probability for a particular period of time (USGS).

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 Vol 2. of DEIR.

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

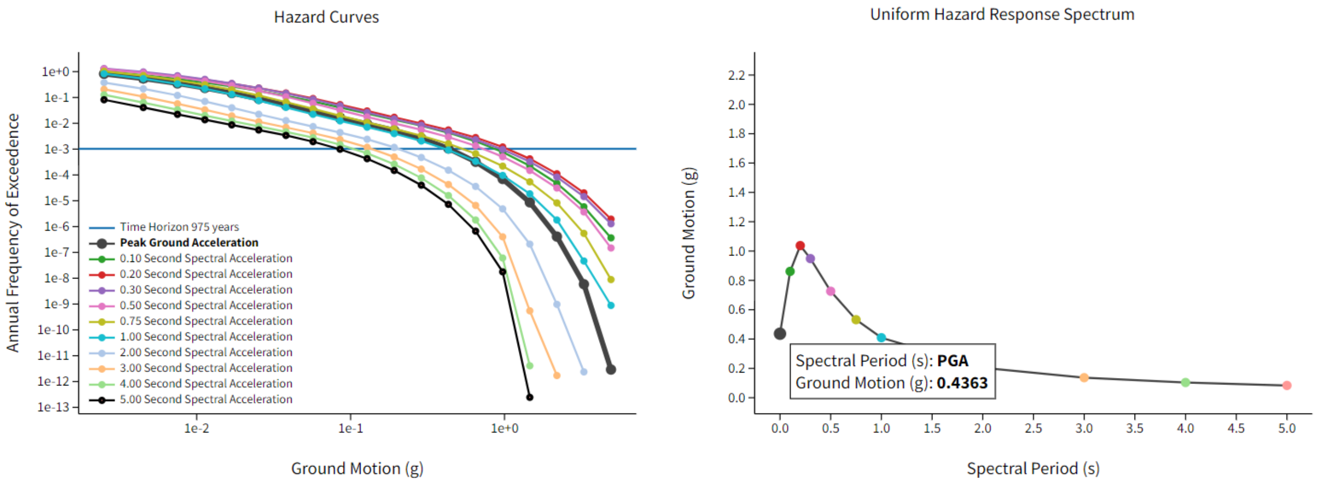


Figure 4. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 5% in 50 years. For an annual frequency of exceedance of 1.025E-03 or return period (inverse of frequency of exceedance) of 975 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 (DEIR, 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 5) (not included in the DEIR) indicates a peak ground acceleration of 0.3175g having a 10% probability of exceedance in 50 years, 19% probability in 100 years and a 64% probability of exceedance in 400 years. Care was taken in these calculations to ensure that r* ≤ 1 where r* = r(1+0.5r) and r = probability as recommended by USGS (USGS, 2024).

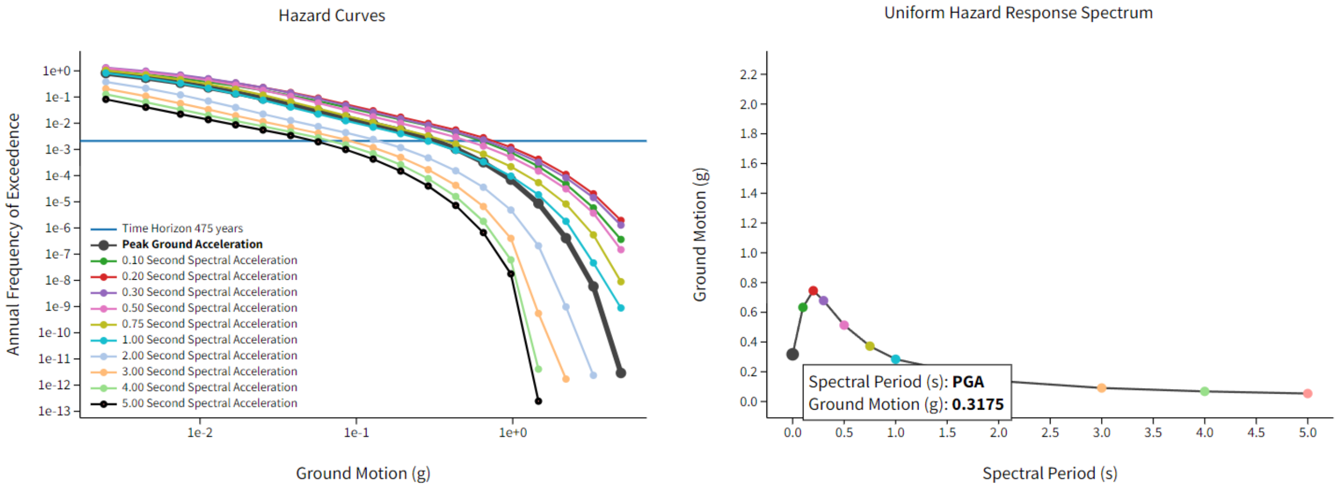


Figure 5. Generation of hazard curves for the site location (latitude 35.325027, longitude, -119.544935) using the USGS Unified Hazard Tool for a probability of exceedance of 10% in 50 years. For an annual frequency of exceedance of 2.105E-03 or return period (inverse of frequency of exceedance) of 475 years, peak ground acceleration = 0.3175g (31.75% of the gravitational constant).

Comment: In Volume 1 of the DEIR, in Impact 4.7-1, it is stated, *“an earthquake may disturb surface and/or subsurface facilities, possibly resulting in loss, injury, or death. Impacts from seismic hazards are considered potentially significant without mitigation and MM 4.7-1 would be required to reduce these potential impacts to a less-than-significant level for this individual project impacts.”* Mitigation measure 4.7-1 consists of preparing *“a comprehensive seismic activity monitoring plan that includes, but is not limited to, connection to the Statewide seismic monitoring program of California Seismic Network (CISN)…The final plan shall be approved by the California Air Resources Board and include all requirements of State law including but not limited to: Appropriate subsurface monitoring to ensure geologic sequestration of injected carbon dioxide; Identification of hazards and conditions that may require the suspension of carbon dioxide injections; notification protocols for all applicable agencies and emergency procedures. All requirements for seismic monitoring adopted by the California Air Resources Board – Carbon Capture, Removal, Utilization and Storage Program shall be implemented.”*

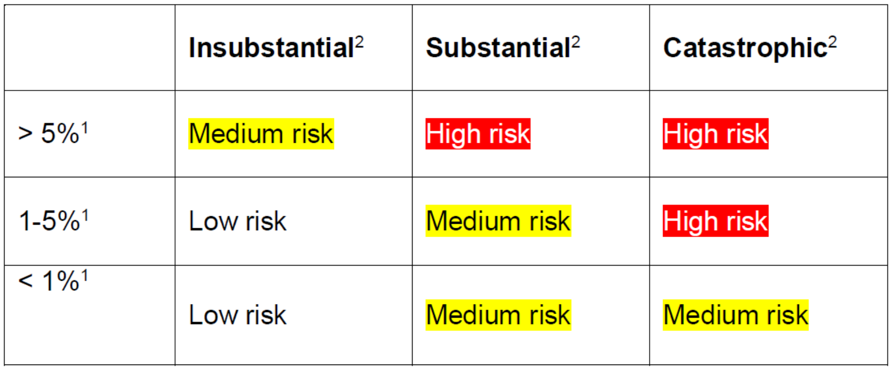
While a seismic monitoring plan would be able to detect an earthquake, a seismic monitoring program would not reduce damage to surface and subsurface facilities (e.g., wellbores). Unlike induced seismicity as a result of injection of CO_2, monitoring of natural seismicity is not mitigation. Cement used outside of well casing is a brittle material susceptible to damage from ground motion. Hence, a seismic monitoring program would not mitigate damage from a natural major earthquake within 100 km of the Carbon TerraVault I project to a less-than-significant level. In the presence of moderate seismic activity at the project area (e.g., MMI ≥ 5, PGA ≥ 0.05g, PGV ≥ 3.0 cm/s), mitigation should include assessment of leakage at wellbores and reentry and replugging of wellbores in the event of increased leakage from wellbores. The Level of Significance for Impact 4.7-1 should be changed from Less than Significant to Significant and Unavoidable.

Comment: In Volume 2 of the DEIR, Soils Engineering Inc. states, *"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, however. It is not clear whether wellbores can withstand a peak ground acceleration of 0.258g, let alone peak ground accelerations of 0.3175g or 0.4363g. A peak ground acceleration of 0.27 g is associated with a Modified Mercalli Intensity of VIII with observations including: steering of motor cars affected; damage to masonry and some masonry walls; twisting, fall of chimneys, factory stacks, monuments, towers, elevated tanks; frame houses moved on foundations if not bolted down; loose panel walls thrown out; changes in flow or temperature of springs and wells; and cracks in wet ground and on steep slopes. Hence, this mitigation measure is not appropriate, at least for wellbores like those that would be impacted at Elk Hills. Also, Templeton et al. (2021) state that an evaluation of the anticipated losses as a function of ground motion intensity can be achieved either directly by using vulnerability functions or indirectly through the use of fragility functions. Vulnerability functions directly relate ground motion intensity to anticipated losses. Fragility functions relate ground motion intensity to the probability of damage and are often expressed as either loss ratio curves, damage probability matrices, or fragility curves (Templeton et al., 2021). There does not appear to be vulnerability and fragility functions associated with oil and gas wellbores. However, based on a Modified Mercalli Intensity of at least VIII, wellbore damage would reasonably be expected from a major seismic event within 100 km of the Carbon TerraVault I project. The Level of Significance for Impact 4.7-2 should be changed from Less than Significant to Significant and Unavoidable. In the presence of moderate seismic activity at the project area (e.g., MMI ≥ 5, PGA ≥ 0.05g, PGV ≥ 3.0 cm/s), mitigation should include assessment of leakage at wellbores and reentry and replugging of wellbores in the event of increased leakage from wellbores.

Comment: CARB requires that an operator use appropriate tools to characterize potential risks of adverse impacts on the environment, health, or safety, by combining the assessment of the probability of occurrence and the magnitude of the adverse impacts of identified project risk scenarios. Risk scenarios identified as part of this assessment must be classified high risk, medium risk, or low risk, according to the combination of probability of occurrence during a 100-year period and the severity of potential consequences (Table 3). Given an approximately 10% and 20% probability of a 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, it is difficult to understand how CTV categorized risk as low to medium (Table 4). Risk in assigned scenarios should be classified as high. At a minimum, this high risk classification should mandate robust evaluation and monitoring of wellbore integrity.

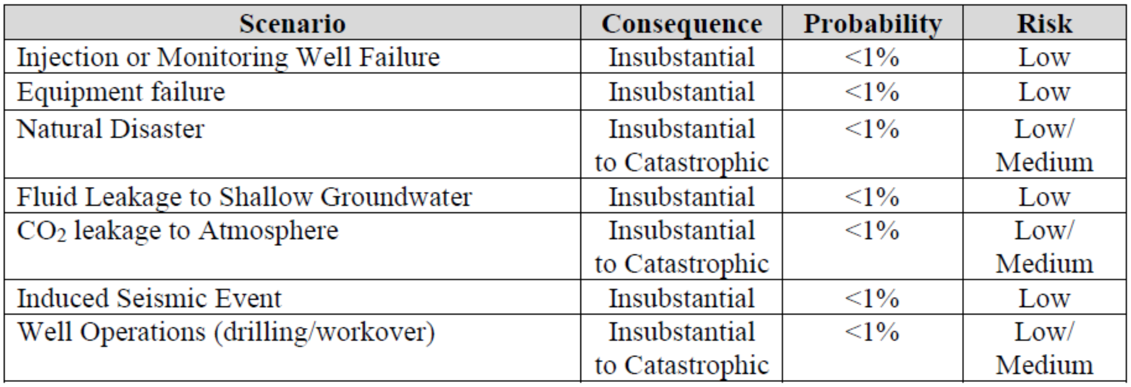
Table 3. CARB Risk scenario classification.



	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

Table 4. Risk Assessment Results from Volume 2 of DEIR



Scenario	Consequence	Probability	Risk
Injection or Monitoring Well Failure	Insubstantial	<1%	Low
Equipment failure	Insubstantial	<1%	Low
Natural Disaster	Insubstantial to Catastrophic	<1%	Low/ Medium
Fluid Leakage to Shallow Groundwater	Insubstantial	<1%	Low
CO_2 leakage to Atmosphere	Insubstantial to Catastrophic	<1%	Low/ Medium
Induced Seismic Event	Insubstantial	<1%	Low
Well Operations (drilling/workover)	Insubstantial to Catastrophic	<1%	Low/ Medium

Additional Hazard from Induced Seismicity

Induced seismicity is of concern for faults that are optimally oriented, critically stressed, and of sufficient size to cause damage sufficient to induce leakage of sequestered CO_2. Leakage of CO_2 could occur through a damaged confining layer, from activation of faults penetrating a confining layer, or through wellbore damage.

Induced seismicity considerations in the Class VI regulations are largely limited to CO_2 migration through faults penetrating the confining layer. EPA (2013) states that use of seismic hazard maps to demonstrate the reasonable expectation that no induced seismic events would occur during the course of a CCS project may fulfill the requirements at 40 CFR 146.82(a)(3)(v). However, if such maps indicate a substantial likelihood of seismic activity, other required geologic information, such as geomechanical data, depth to confining zones, and fault stability analysis may be needed to demonstrate that seismic activity will not compromise subsurface containment (EPA, 2013) An owner/operator is required to determine the "location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the Area of Review, along with a determination that they will not interfere with containment" (40 CFR 146.82(a)(3)(ii)). The owner/operator is also required to demonstrate the presence of a "confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced fluids" (40 CFR 146.83(a)(2)).

It is stated in the Class VI permit applications that in 2019 three-dimensional (3D) seismic survey data was re-processed to allow a more focused structural image around tight folds and faults (EPA, 2024). Offsetting the 31S anticline are high-angle reverse faults that are oriented NW-SE. It is stated that these inactive faults penetrate the lowest portions of the Monterey Formation but not the lower Reef Ridge Shale above the Monterey Formation in the 26R reservoir. It is also stated the 26R reservoir is continuous across the Area of Review and the sands pinch-out up-dip and on the channel edges. As such, the 26R reservoir has minimal connection outside the Area of Review creating a reservoir with no connection to regional saline aquifers (EPA, 2024). The emphasis of EPA regulations are on upward migration of brine and CO_2 as opposed to downward propagation of pressure. The concern with faults in the Monterey Formation may be uncertainty associated with potential propagation of pressure below the storage formation, such as has occurred during disposal of produced water in Class II disposal wells and during hydraulic fracturing.

Increased subsurface fluid injection activity has led to increased seismicity at some sites, including near oil and gas wastewater (produced water) disposal sites, hydraulic fracturing sites, and engineered geothermal systems (Ellsworth, 2013; Keranen and Weingarten, 2018; Templeton et al., 2020). Induced seismicity has raised concerns about the scalability of geologic storage of CO_2 considering the seismic hazard and risk associated with far-reaching subsurface pressurization and adjacent basement rocks (Zoback and Gorelick, 2012; White and Foxall, 2016). Even in areas of low to moderate natural seismic activity, fluid injection may induce earthquakes in excess of **M** 4 (Templeton et al., 2023).

Seismogenic response to fluid injection may vary strongly from site to site and between different injection intervals (Templeton et al., 2023). Weingarten et al. (2015) and Schultz et al. (2018) show that the potential for inducing earthquakes in wastewater disposal and hydraulic fracturing, respectively, correlates positively with the total injected fluid volume and the rate of injection. However, the causative mechanisms of induced seismicity and geomechanical conditions at injection sites are diverse and involve many poorly constrained or unknown parameters. Significant uncertainties on the likelihood of inducing seismicity can persist even after careful characterization. It is not fully understood why some operations can cause significant induced seismicity while others do not (Templeton et al., 2021).

Before 2011, the **M** 4.8 event in 1967 near Denver, Colorado, was the largest event widely accepted in the scientific community as having been induced by fluid injection. The Rocky Mountain Arsenal earthquakes demonstrated how the diffusion of pore pressure within an ancient fault system can initiate earthquakes many kilometers from the injection point, delayed by months or even years after injection ceased (Hermann et al. 1981). The **M** 5.7 event in November 2011 in central Oklahoma is now the largest known induced seismic event (Kerenan et al., 2013). This earthquake damaged homes and unreinforced masonry buildings in the epicentral area and was felt as far as 1000 km away in Chicago, Illinois.

Seismicity may be induced tens of kilometers away from large-scale injection. The occurrence of seismicity farther away from injection implies that stress changes much smaller than 1 MPa may be sufficient to trigger seismicity even in naturally quiescent areas. Recent studies indicate that effective stress changes on the order of 100 kPa (14.5 psig) or less can found near earthquake hypocenters (Keranen et al., 2014; Barbour et al., 2017; Norbeck and Rubinstein, 2018; Zhai et al., 2020).

Even faults capable of **M** 5 earthquakes may be previously unknown. In many of the induced seismicity cases, faults that hosted even the largest events > **M** 5 were not known beforehand (Templeton et al., 2023). Even natural events, such as the 2014 Napa, California earthquake, often occur on blind faults (Brocher et al., 2015). This can be related to the difficulty of imaging faults in basement rocks or the lack of vertical offset in the sedimentary overburden from subvertical strike-slip faults.

The largest injection-induced events have all involved faulting that is considerably deeper than the injection interval (Horton, 2012), suggesting that transmission of increased pressure into the basement elevates the potential for inducing earthquakes. Hence, during geologic storage of CO_2, it is important that pressure perturbation from injection not be transmitted below depths of injection.

Few commercial scale geologic CO_2 storage sites exist that can be used as prototypes to study induced seismic response. The Cogdell CO_2 enhanced oil recovery project has been associated with felt earthquakes. The seismicity in the Cogdell project has been attributed to the very high injection rates and the presence of faults in the reservoir (Gan and Frohlich 2013). At the Illinois basin–Decatur project and the associated Illinois Industrial Carbon Capture and Sequestration Sources project, as of 2022, 2.8 million metric tons of CO_2 have been injected into the Mt. Simon saline sandstone reservoir with detection of nearly 20,000 seismic events with **M** up to 1.2, although none have been felt at the surface (Williams-Stroud et al., 2020). As a result of seismic activity, injection was moved to a shallower zone within the Mt. Simon sandstone resulting in fewer seismic events (Williams-Stroud et al., 2020).

Dvory and Zoback (2021) state that since depleted oil and gas fields have decreased pore pressure compared to initial conditions, it is plausible that the risk of induced seismicity in depleted oil and gas fields may be less than that associated with other storage configurations (e.g., saline aquifers) because increased pore pressure beyond initial conditions is one of the main causes of injection-induced seismic events.

One study of particular relevance to the Carbon TerraVault I project is a potentially injection-induced earthquake swarm in 2005 associated with the WhiteWolf Fault (Goebel et al., 2016). It was comprised of a **M** 4.5 event on 22 September, followed by two **M** 4.7 and **M** 4.3 events the same day. The White Wolf swarm is suspected to be connected to fluid-injection activity at the Tejon Oil Field based on a statistical assessment of injection and seismicity rate changes (Goebel et al., 2015). Injection wells at the Tejon Oil Field targeted a 25–30 m thin, highly permeable stratigraphic zone within the Monterey formation composed of turbiditic sand lenses with maximum lateral extents of 1 to 2 km (Goebel et al., 2016). Recall that turbiditic sand lenses are targeted for CO_2 storage at the Carbon TerraVault I project.

Based on geological mapping, seismicity, and well-log data, Goebel et al. (2016) identified a seismically active normal fault referred to as "Tejon Fault" in proximity to the Tejon Oil Field which deepened (7.7 km) toward the northwest below the Wheeler Ridge fault before intersecting with the White Wolf Fault 8 km from injection wells (Figure 6). Pressure diffusion was likely influenced by a 11 km high permeability pathway along the seismically active part of the Tejon fault (Goebel et al., 2016). Numerical modeling indicated that for a fault zone permeability above ~300 mD and fault width below ~800 m, a pressure increase of just 0.01 MPa (1.5 psi) was sufficient to induce seismicity on a fault favorably oriented to slip (Goebel et al., 2016) as also observed by Keranen et al. (2014) and Hornbach et al. (2015). Given the discussion here, the primary concern at the Carbon TerraVault I project is pressure transmission below the Monterey Formation, not above it. Investigative studies have demonstrated that pressure propagation can occur over large distances and depths during injection of fluids and that a very small pressure differential can induce seismicity. Hence, analysis conducted by CTV in the DEIR and Class VI permit applications does not eliminate the potential for inducted seismicity at the Carbon TerraVault I project.

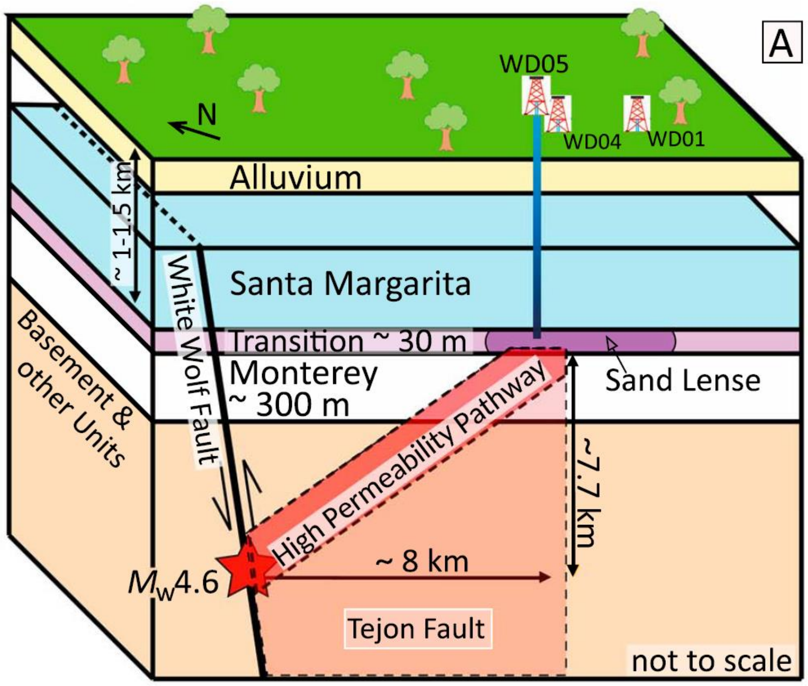


Figure 6. Schematic representation of pressure migration along a high-permeability fault between the Tejon Oil Field and a M 4.6 seismic event along the White Wolf Fault.

Comment: For induced seismicity, the primary concern here is pressure transmission below the Monterey Formation, not above it. In the Class VI regulations, the primary concern is leakage through faults in the confining layer, not transmission of pressure and induced seismicity below the storage formation. Hence, neither EPA regulations nor the DEIR adequately consider induced seismicity. Callas et al. (2022) state that lack of a lower confining seal (permeability > 100 nD) (nD = 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 2 of the DEIR, the Reef Ridge Shale bounds both the upper lower Monterey Formation and has an average permeability of 0.01 mD (mD=millidarcy) or 10,000 nD. As discussed, in the 26R and A1 - A2 Storage Areas, CTV states that final pressure will target the initial reservoir pressure at the time of discovery. Hence, this would decrease but not eliminate the possibility of induced seismicity.

Seismic Monitoring Network Design

The Class VI regulations do not include an explicit requirement for a seismic monitoring plan. However, in its Class VI Implementation manual for UIC Program Directors, EPA states that concerns about seismicity or uncertainties about the seismic history of the site raised during site characterization may necessitate the inclusion of passive seismic monitoring (EPA, 2013).

Seismic data needs to be gathered, analyzed, and archived during the lifetime of a project for geologic storage of CO_2. These data are needed to accurately assess and periodically reassess the natural and induced seismic hazard and risk associated with the project and to aid in the rapid and effective detection and characterization of the seismicity at the site. This data is especially needed as input into induced seismicity mitigation plan protocols (e.g., traffic light systems). In general, the National Earthquake Information Center (NEIC) and other national or state monitoring systems are not sufficient for monitoring induced seismicity at a facility for geologic storage of CO_2 (Templeton et al., 2021). Routine detection of small events in the immediate vicinity of the injection site is necessary to detect problematic developments as early as possible.

The California Carbon Capture and Storage Review Panel recommended that seismic risks be considered during the operation and monitoring of CO_2 storage projects and stated that specialized seismic monitoring may be warranted (California Institute for Energy and Environment, 2010). The CARB protocol for CO_2 sequestration requires that the operator deploy and maintain a permanent, downhole seismic monitoring system to determine the presence or absence of any induced micro-seismic activity associated with all wells and near any discontinuities, faults, or fractures in the subsurface (CARB, 2018). Templeton et al. (2023) state that to record seismicity within the ROC, it is expected that the footprint of the seismic network would need to extend beyond the ROC. In the 26R Reservoir and A1 - A2 Area of Review areas, CTV will monitor seismicity with a network of surface and shallow borehole seismometers. Specifically, CTV will deploy 6 sensor locations (borehole and near surface) most of which are outside the Area of Review. CTV states that this data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

The Technical Advisory Committee to the California Carbon Capture and Storage Review Panel recommended that monitoring for induced seismicity should begin during the site selection and assessment phase to establish a baseline record of the natural background seismicity in the region encompassed by the project using the state's existing seismometer network augmented by a local network. Templeton et al. (2023) recommend that prior to commencing injection operations, a seismic monitoring network should be operated for at least 6 months but preferably 1 year or longer and be designed to detect and characterize seismicity occurring in the ROC down to at least **M** 1. CTV states in the Class VI permit application that a seismic monitoring network will establish an understanding of baseline seismic activity within the area of the project and that historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline.

Comment: Templeton et al. (2023) state that a local seismic monitoring network should include a combination of high-gain sensors, which can optimally record weak ground motions from small local earthquakes, and low-gain accelerometers, which can optimally record strong ground motions from nearby larger earthquakes. Templeton et al. (2023) also state that each seismic station should measure ground motion in three orthogonal directions (e.g., up-down, north-south, and east-west) to fully capture the movement of the seismic waves as they travel through the earth. CTV states that high-sensitivity 3-component geophones will be utilized for seismic monitoring (DEIR, 2024b). CTV also states that CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. It is unclear whether the seismic monitoring network is of sufficient robustness. CTV should provide additional information on specification of geophones to be used for seismic monitoring.

Comment: Information on the resolution of the CTV I seismic network is lacking and should be provided in the DEIR and Class VI permit applications. Templeton et al. (2023) state that the 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.

Comment: Templeton et al. (2023) state that seismic monitoring networks should be designed, and stations located such that ground velocities of 600 nm/s can be recorded with a signal-to-noise ratio of at least 6 in the frequency range 5–40 Hz within the ROC. Information on the signal-to-noise ratio in the seismic network is lacking and should be provided in the DEIR and Class VI permit applications.

Comment: Templeton et al. (2023) state that the data should be recorded using at least a 24-bit digital data acquisition system and a global positioning system-based field timing system to achieve the required timing accuracy of at least 1 ms. CTV states that waveform data is to be transmitted near real-time via cellular modem or other wireless means and archived in a database (DEIR, 2024b). Timing accuracy was not specified in the DEIR and the Class VI permit applications.

Seismicity Mitigation Plan

If the project operator obtains evidence that an earthquake has caused a failure of the mechanical integrity of wells, facilities, or pipelines, which may cause potential CO_2 emissions to the atmosphere, the project operator must implement an Emergency Remedial Response Plan (CARB, 2018). The operator should create a site-specific induced seismicity mitigation plan for the DEIR based on a Traffic Light System (TLS) framework (Templeton et al., 2023). Templeton et al. (2023) state that the TLS framework should include at least three response levels, indicating operation as usual (green), heightened awareness and reassessing and modifying as appropriate of injection operations (yellow), and stopping injection (red). In the Class VI permit application, CTV created a five-response level (green, yellow, orange, magenta, red) seismicity mitigation plan.

Comment: CTV established response levels based on the magnitude of a seismic event. For an induced seismic event having **M** > 2.0, in the Class VI permit application, CTV states that it will initiate gradual shutdown of the injection wells if it is determined "*appropriate*". Words like "*appropriate*" are vague and don't provide measurable performance criteria, per CEQA requirements. CTV also states that it will monitor well pressure, temperature, and annulus pressure 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 (DEIR, 2024b). There is no mention of evaluation of any other wellbores, which is a critical oversight.

The CARB protocol for CO_2 sequestration requires that the operator continuously monitor for indication of an earthquake of **M** 2.7 or greater occurring within a radius of one-mile of injection operations. If an earthquake of **M** 2.7 or greater is identified, CARB, in consultation with the project operator and the California Geological Survey, or local geological survey or equivalent, must conduct an evaluation of the following: (a) whether there is indication of a causal connection between the injection activity and the earthquake; (b) whether there is a pattern of seismic activity in the area that correlates with nearby injection activity; and (c) whether the mechanical integrity of any well, facility, or pipeline within the radius specified in subsection C.4.3.2.3(b) has been compromised (CARB, 2018). Hence, if induced seismicity having a magnitude of **M** 2.7 or larger occurs, the operator must conduct an evaluation of the integrity of *all* wellbores including those plugged and abandoned.

Comment: The preliminary results of the seismic evaluation must be reported to CARB within 30 days following the earthquake, with a final report submitted within 120 days (CARB, 2018). The report must include, at a minimum: (1) the date, time, and magnitude of the earthquake; (2) the location and distance of the epicenter from the CCS project; (3) the results of the investigation into the link between the injection activity and the earthquake or pattern of seismicity; (4) any emergency and remedial actions taken; (5) a description of any investigations and tests conducted to assess the mechanical integrity of wells and other surface equipment, and a demonstration that the well and equipment were either not damaged by the earthquake or that mechanical integrity was restored prior to the re-initiation of injection; and (6) any identified changes necessary to the CCS project Testing and Monitoring Plan (CARB, 2018). There is no mention of reporting of seismic events to CARB anywhere in the seismicity mitigation plan.

Comment: Templeton et al. (2023) state that the seismicity mitigation plan should provide a clear description of mandatory and optional actions and procedures at each of the response levels. CTV repeatedly used the term *"if appropriate"* for initiation of injection well shutdown. The term appropriate is not defined and hence is ambiguous. Words like "*appropriate*" are vague and don't provide measurable performance criteria, per CEQA requirements. It is unclear precisely under what conditions initiation of shutdown would commence for yellow, orange and magenta operating states.

Comment: Of perhaps greater concern are naturally occurring seismic events at distance from the facility. In these cases, a seismic mitigation plan specified in terms of peak ground velocity or ground acceleration would be more useful in the DEIR and Class VI permit application.

Conclusions and Recommendations

There is interest in using depleted oil and gas reservoirs, such as the Carbon TerraVault I project for geological storage of CO_2 due to extensive preexisting geological characterization and infrastructure. Also, since depleted oil and gas fields have decreased pore pressure compared to initial conditions, it is plausible that the risk of induced seismicity in depleted oil and gas fields may be less than that associated with other storage configurations (e.g., saline aquifers) because increased pore pressure beyond initial conditions is one of the main causes of injection-induced seismic events.

However, well penetrations are widely recognized as a primary pathway for leakage during geologic storage of CO_2. There are an extraordinarily large number of wellbores (354) penetrating the primary confining layer (Reef Ridge Shale) at the Carbon TerraVault I project. Leakage through wellbores will be facilitated by the high pressure of storage (~4,000 psi) and storage occurring primarily as a separate phase supercritical fluid. All 354 wellbores will eventually be in direct contact with highly pressurized supercritical CO_2 – a highly corrosive medium.

Complicating matters further is the fact that that the Carbon TerraVault I project is located in an area of high natural seismicity. The probability of a natural seismic event capable of causing wellbore damage in the project area is quite high (~20% within 100 years). Given the large number of well penetrations, high pressure during storage, storage primarily as a supercritical fluid, and natural seismicity, leakage through well penetrations is a major concern. The success or failure of geologic storage of CO_2 at the Carbon TerraVault I project will largely depend on minimizing leakage from well penetrations.

The importance of properly evaluating wellbores prior to plugging to determine the need for corrective action and evaluating wellbores that have been plugged sometime in the past cannot be stressed enough. Unfortunately, only a table identifying well penetrations was provided in the Class VI permit applications. No identification of well penetrations was provided in the Draft Environmental Impact Report. CTV claims that no wellbores require corrective action – a claim that must be viewed with considerable skepticism since wellbore integrity failure rates published from oil and gas sites in the literature range from 2 to 75%.

In one column of the table provided in the Class VI permit applications, annular isolation of wellbores within the upper confining later is subjectively described as "*adequate.*" No proof of adequacy of any wellbore beyond those used for injection was provided in the DEIR or Class VI permit applications. CTV should immediately submit all supporting information (drilling logs, well completion and plugging reports, casing and cementing records, records on internal and external mechanical integrity testing, cement bond/variable density logs, and wellbore diagrams) to the public record. Also, EPA should conduct an evaluation of each well penetration – something that the agency should have done but does not appear to have done so. Simply accepting CTV's claim of adequacy is unacceptable.

In the absence of a robust investigation of wellbore integrity at the Carbon TerraVault I project, neither the DEIR nor the Class VI permit applications should be approved.

Funding

Funding for this report was supplied by the Center for Applied Environmental Science at the Environmental Integrity Project.

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