Appendix F

Carbon Dioxide (CO_2) Sequestration

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GEOLOGIC SEQUESTRATION OF CO_2 AND ENHANCED OIL RECOVERY (EOR)

Capture and sequestration (storage) of CO_2 that would otherwise be emitted from industrial activities provides a method to reduce greenhouse gas emissions and reduce human contributions to the atmospheric CO_2 concentration. There are a number of options which can help slow worldwide anthropogenic greenhouse gas emissions, including energy efficiency improvements, renewable energy sources, nuclear power, increased use of biological carbon sinks, and Carbon Capture and Sequestration (CCS).

The importance of CCS in addressing climate change is recognized in California's Senate Bill No. 1368 (SB 1368) which was signed into law in 2006. SB 1368 is the world's first greenhouse gas emission performance standard set for power plants. (See Cal. Pub. U. Code §§ 8340; 8341.) SB 1368 mandates specific requirements for future power generators and provides in pertinent part as follows:

> *(a) No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard. . . . (d)(5) Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard.*
> (See Cal. Pub. U. Code § 8341 (a); (d)(5) (emphases added).)

The Hydrogen Energy California (HECA) project (Project), located in Kern County, California, will utilize Integrated Gas Combined Cycle technology to capture over 90 percent of potential CO_2 emissions from the synthetic gas that is produced during steady state operations. During operations, the Project is expected to deliver an annual average rate of 110 million standard cubic feet per day (mmscf/d) of CO_2 (approximately 2.2 million tons per year). This CO_2 will be compressed and transported via pipeline to the custody transfer point at the adjacent Elk Hills Field, where it will be injected. The CO_2 EOR process involves the injection and reinjection of CO_2 to reduce the viscosity and enhance other properties of the trapped oil, thus allowing it to flow through the reservoir and improve extraction. During the process, the injected CO_2 becomes sequestered in a secure geologic formation. This process is referred to, herein, as CO_2 EOR and Sequestration. The Elk Hills Field is considered an excellent long-term sequestration site based on studies conducted by HECA, which investigated geologic, and seismic conditions, engineering considerations and the proximity to Project Site, as well as publicly available data (Advanced Resources International 2004). The EOR operation will employ existing, well-tested technology that is protective of human health and the environment and minimizes potential risk. As a result, the Project will provide low-carbon power and additional oil reserves, while generating revenue for the state and creating hundreds of jobs.

CO_2 has been naturally sequestered in geologic formations for hundreds of millions of years. The capture of CO_2 emissions and injection into such formations has been safely practiced on an industrial scale for decades, particularly in oil and gas reservoirs. The U.S. EPA has recognized that oil and gas reservoirs will play a valuable role in the geologic storage of CO_2. Two of the reasons cited by EPA are: (1) oil and gas reservoirs are natural storage containers that have trapped fluid (both liquid and gaseous) hydrocarbons for millions of years; and (2) oil and gas exploration and production activities have created a wealth of knowledge and geologic data that can support the site characterization process for geologic sequestration. (See EPA's *Proposed Rule: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells*, 73 Fed. Reg. 43492-541, July 25, 2008). These reservoirs are well studied and they offer the best early opportunity for large-scale geologic sequestration of CO_2, building on 100 years of oil and gas field operating experience and the oil industry's more than 35 years of CO_2 EOR experience.

Early CO_2 sequestration projects in connection with EOR will significantly advance the deployment of CCS technology and geologic sequestration of CO_2 for many reasons:

- Oil and gas formations offer the best characterized sites among those identified as potential geologic CO_2 sinks;
- Much of the required infrastructure and operational experience is already in place;
- Existing regulations (EPA Underground Injection Control Class II well requirements) have proven to be effective in protecting Underground Sources of Drinking Water ("USDWs") in the context of CO_2 EOR operations, evidenced by more than 30 years of experience in the Permian Basin and more than 25 years of miscible gas injection projects on the North Slope of Alaska (where CO_2 comprises 25 percent of the miscible gas injected); and
- Demand for large volumes of CO_2 for EOR is increasing and presently exceeds 2 billion cubic feet per day

In 2005, the Intergovernmental Panel on Climate Change (IPCC) released a report, *Carbon Dioxide Capture and Storage* (the "IPCC CCS Report")**.** The IPCC CCS Report was written by 125 contributing authors, and was extensively reviewed by over 200 others, including technical experts and government representatives from around the world. The IPCC CCS Report carefully weighs the technologies and the potential risk and concludes that, with appropriately selected and managed sites, CO_2 may be permanently sequestered. The IPCC CCS Report notes that the early commercial scale CCS projects will probably employ CO_2 sequestration with EOR as their basis of design, which will extensively inform the technical development and safe deployment of CCS projects in other types of geologic formations.[1]

CO_2 EOR has the added benefit of increasing domestic U.S. energy supplies in the face of increasing energy demand. High volume injection of CO_2 for EOR, similar to the volumes anticipated with the HECA project, began in West Texas in the early 1970s. CO_2 EOR has proven capable of increasing oil production and extending the life of mature oil fields. The U.S. Department of Energy (DOE) (See DOE-NETL 2008) estimates that CO_2 EOR has the potential to increase total U.S. oil reserves by 45-85 billion barrels of oil (bbo), which is 2 to 4 times the current United States' total proven reserve. A significant portion of these potential oil reserves are in California (5 to 6 bbo). In addition, the DOE report notes that oil and gas reservoirs can be ideal candidates for sequestration of CO_2 since oil and gas reservoirs have proven capable of storing fluids and gasses for millions of years, and replacing the extracted oil and hydrocarbon gas with CO_2 is an excellent use of this natural reservoir. Importantly, not only does sequestration of CO_2 occur during active EOR operations, but it continues after EOR operations cease.

[1] Notably, it is estimated that site characterization of saline reservoirs will likely cost tens of millions of dollars and it would take a decade or more to develop one large-scale commercial saline storage reservoir project exceeding 2 million tons/year of CO_2.

OVERVIEW OF CO_2 EOR AND SEQUESTRATION

A CO_2 sequestration project that does not include EOR is different from one that includes both elements. The goal of a sequestration-only project is to inject and store CO_2 in a contained subsurface environment, while the aim of an EOR and sequestration project has a dual purpose – to use the CO_2 to permit the extraction of hydrocarbons (oil and gas) from the reservoir and, in the process, store injected CO_2, safely in the reservoir. During the EOR process, the volume of oil and gas produced from the reservoir is expected to offset the purchased volume of CO_2 injected into the reservoir. Therefore, the combination of CO_2 EOR with sequestration not only eliminates any undesirable reservoir pressure increase, but the extraction of oil and gas volumes will allow the storage of greater CO_2 volumes. During EOR operations, the pore space voided by the produced hydrocarbons serves as the storage space for the injected CO_2.

In EOR operations, supercritical[2] CO_2 is injected into the reservoir through wells specially designed for this purpose. Injection occurs at a pressure high enough to facilitate transfer of the desired volume of CO_2 into the reservoir where it can contact the oil, but well below pressures that could fracture the confining geologic zone. Due to the induced pressure gradient, the CO_2 flows away from the injection well (see Figure 1). As it does a portion of the CO_2 contacts and mixes with the oil to form a single-phase solution (i.e., the CO_2 and oil are miscible). The portion of CO_2 that mixes with the oil is dependent upon characteristics of both the hydrocarbon reservoir (i.e., pressure and temperature) and the chemical composition of the reservoir fluids. The resulting miscible fluid has the favorable properties of lower viscosity, enhanced mobility and lower interfacial tension as compared to the oil alone. This helps to mobilize oil that might otherwise be trapped in the rock, and results in increased oil production. Often, water injection is used to sweep the miscible-CO_2 and oil mixture to production wells.

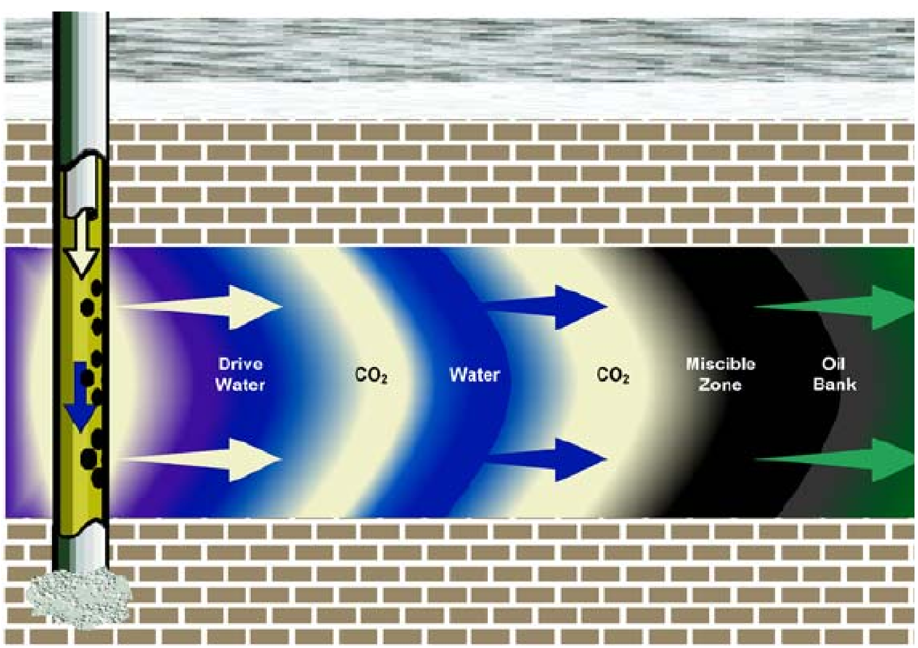


Figure 1: Schematic of miscible-CO_2 flood (courtesy of Occidental)

[2] The temperature and pressure conditions above which a phase boundary (such as between a liquid and gaseous state) ceases to exist.

Currently, in commercial scale EOR projects, operators purchase CO_2 for injection or produce it from natural formations. Since this can represent a significant portion of the cost of an EOR project, the operations are designed to minimize CO_2 procurement and maximize oil production. This is accomplished by separating the CO_2 from the produced hydrocarbons and recycling the CO_2 within an enclosed system back to the reservoir as part of the continuous EOR process. Injected CO_2 is monitored closely to ensure economic operation as CO_2 is a valuable commodity to EOR operators. However, sequestration of CO_2 within the pore spaces of the formation occurs with each injection cycle, necessitating the introduction of additional amounts of CO_2 to continue the EOR operation. For these well-selected, designed and managed geological storage sites, the CO_2 will be immobilized by various trapping mechanisms and be retained indefinitely without release to the atmosphere[3]. A schematic of a typical miscible-CO_2 EOR operation is shown in Figure 2 below.

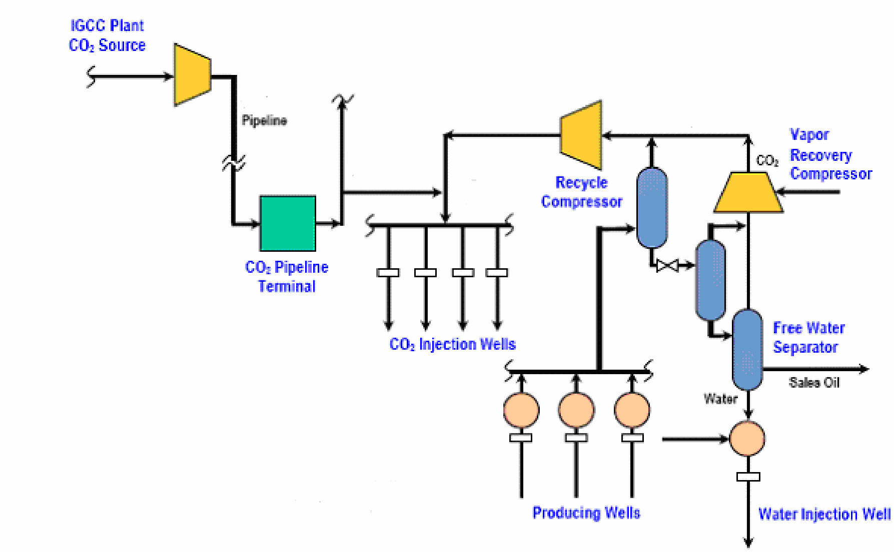


Figure 2: CO_2 EOR Surface Process Schematic

The key trapping mechanisms that occur in the subsurface to indefinitely sequester the CO_2 include physical trapping, residual gas trapping and geochemical trapping.

- Physical trapping (and trap filling) retains the CO_2 in the formation using structural and stratigraphic traps with low permeability formations and faults. Physical trapping of the buoyant CO_2 is provided by the same impermeable "caprock" seal that traps the oil and hydrocarbon gases.

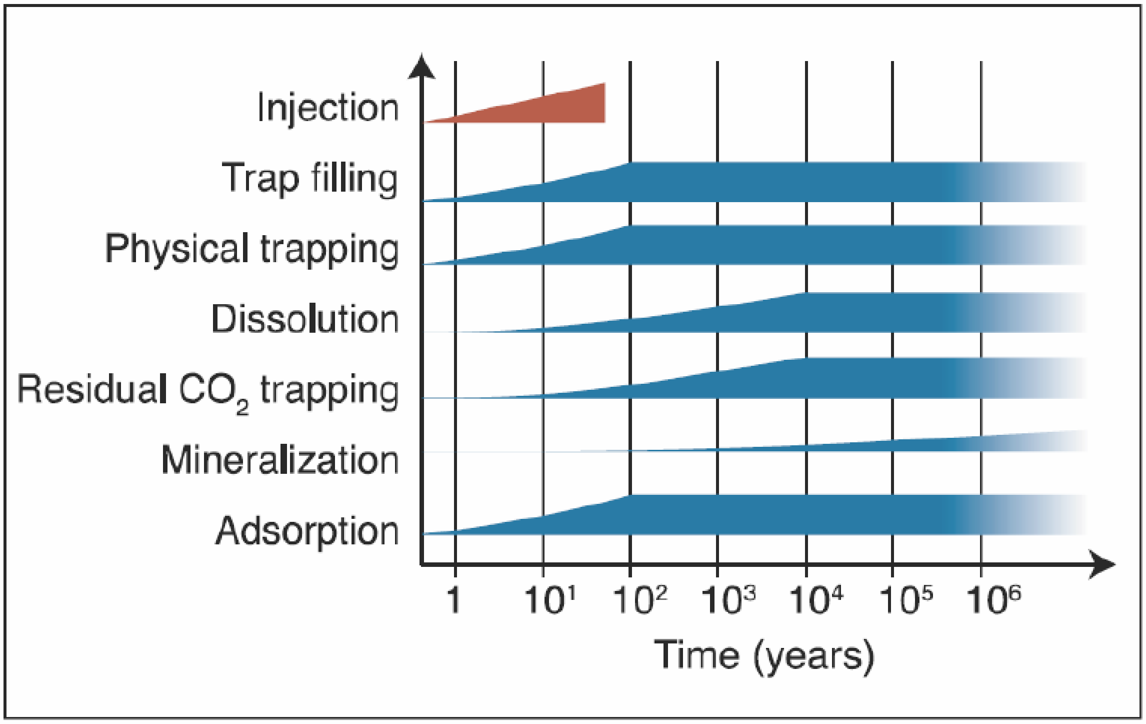
- Residual trapping and dissolution of the liquid or gaseous CO_2 occurs as a result of capillary forces permanently retaining some of the CO_2 as disconnected droplets. Residual trapping is

[3] Even where EOR operators have attempted to reproduce the CO_2 after production at a particular field is completed (for use in another field), approximately 30 percent to 50 percent of the injected CO_2 volume typically remains permanently stored in the oil or gas reservoir and is unrecoverable.

analogous to residual oil saturation (i.e., "trapped" oil) that remains after an oil reservoir is swept with injected water.

- Geochemical trapping describes a series of reactions of CO_2 with natural fluids and minerals in the target formation, principally consisting of CO_2 dissolution in brine (i.e., solubility trapping), CO_2 precipitation as mineral phases (i.e., mineral trapping) and CO_2 sorption onto mineral surfaces. Scientific research is continuing to increase the understanding of the chemical processes involved in geochemical trapping.

These trapping mechanisms operate on different time scales, beginning with initial injection of CO_2 and have different capacities to trap CO_2. The following schematic, Figure 3, depicts the various trapping mechanisms and time horizons.



Source: Metz, B.E.A., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_Chapter4.pdf>.

Schematic shows the time evolution of various CO_2 sequestration mechanisms operating in deep formations during and after injection. Time is shown on an exponential scale were 10^1 is 10 years, 10^2 is 100 years, and so on.

Figure 3: Types and Timescales of CO_2 Sequestration Mechanisms

CO_2 EOR AND SEQUESTRATION REQUIREMENTS

The CO_2 EOR and Sequestration will require the review and approval of the Division of Oil, Gas and Geothermal Resources (DOGGR.). The Project must satisfy the requirements of SB 1368 including confirming (1) capacity; (2) containment; and (3) economic feasibility. This Appendix section focuses on the capacity and containment aspects of CO_2 EOR and Sequestration and explains the basis for the Project's decision to sell its captured CO_2 to Occidental of Elk Hills, Inc. ("OEHI"). The California Energy Commission (CEC) has advised that it will rely on DOGGR for the regulation of CO_2.EOR and Sequestration.

CO_2 EOR and Sequestration will utilize injection, production and separation technology employed in the petroleum industry for many decades. The technology, metallurgical equipment requirements, and the operational and emergency procedures are well defined and documented in American Petroleum Institute ("API") standards and recommended practices. Other technologies include: well-drilling, geologic formation analysis, seismicity analysis, computer simulation of static and dynamic reservoir injection and production, injection and storage of natural gas and industrial waste and, monitoring of subsurface fluid movement.

In general, CO_2 EOR and Sequestration demonstrates capacity and containment by the following activities:

- Site characterization that validates the geological model of the storage site and potential leakage pathways;

- Risk assessment that builds upon a practical understanding of the CO_2 in the reservoir over time and confirms that the potential for leakage has been evaluated; and

- A monitoring, measurement and verification (MMV) plan that assesses the performance of the sequestration site (geology and technology) and validates or updates anticipated behavior.

The appropriate implementation of these key areas will ensure the safe and secure operation of CO_2 EOR and Sequestration. The various phases of such a project are as follows:

1. Site Selection;
2. Operations; and
3. Closure.

The next sections discuss these phases within the context of the Elk Hills Field.

SITE SELECTION

Preliminary Sequestration Assessment

The HECA Project conducted a scoping/screening study to assess potential sites for CO_2 sequestration. Two well-studied, geologic basin areas, the Ventura Basin and the southern end of the San Joaquin Basin located in and around Kern County, were targeted based on their sequestration and EOR potential. The study evaluated capacity, containment, and other specific criteria generally deemed important by current industry and scientific standards in sequestration projects and deemed necessary to satisfy HECA Project Objectives. This study identified at least one field within each basin that met these key factors of depth, pressure, lithology, porosity & permeability, structural integrity, and storage capacity:

- Elk Hills Field in the San Joaquin Basin, Kern County
- Ventura Field in the Ventura Basin, Ventura County

Based on this scoping/screening study, the focus of the subsurface effort was then directed to the Elk Hills Field in Kern County. Elk Hills Field was determined to be the preferred field due to its closer proximity to the Project Site, shorter CO_2 pipeline length, previous CO_2 pilot studies, and decreased construction time and requirements – all of which were best aligned with the HECA Project Objectives. The following discussion sets forth the further detailed study of the Elk Hills Field conducted in the site selection phase by the HECA Project.

General Elk Hills Structure and Geology

The Elk Hills Field produces oil and gas from several vertically-stacked Tertiary-aged clastic reservoirs that are draped over a series of thrust-faulted anticlines and encased within multiple layers of sealing shale. Hydrocarbons, of probable Oligocene and Miocene age source, generated in the deep flanks of the Elk Hills structure and/or migrated into the structure from surrounding sub-basins, beginning in the Pliocene (Zumberge et al 2005). The unique combination of multiple porous and permeable sandstone reservoirs, multiple impermeable shale seals and large anticlinal structure make the Elk Hills Field one of the most suitable locations for the extraction of hydrocarbons and the sequestering of CO_2 in North America. The individual structures and geologic horizons within the Elk Hills Field are detailed in the following paragraphs.

At the surface Elk Hills Field is a large WNW-ESE trending anticline, approximately 17 miles long and over 7 miles wide. With increasing depth the structure sub-divides into three distinct anticlines, separated at depth by high angle reverse faults (Figure 4). The anticlines are believed to have formed in a transpressional regime associated with formation of the San Andreas Fault, beginning in the Middle Miocene (Callaway and Rennie Jr., 1991). The anticlines, labeled 29R, 31S and Northwest Stevens (Figure 4), formed bathymetric highs on the deep marine surface, affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds (Figures 5 and 6).

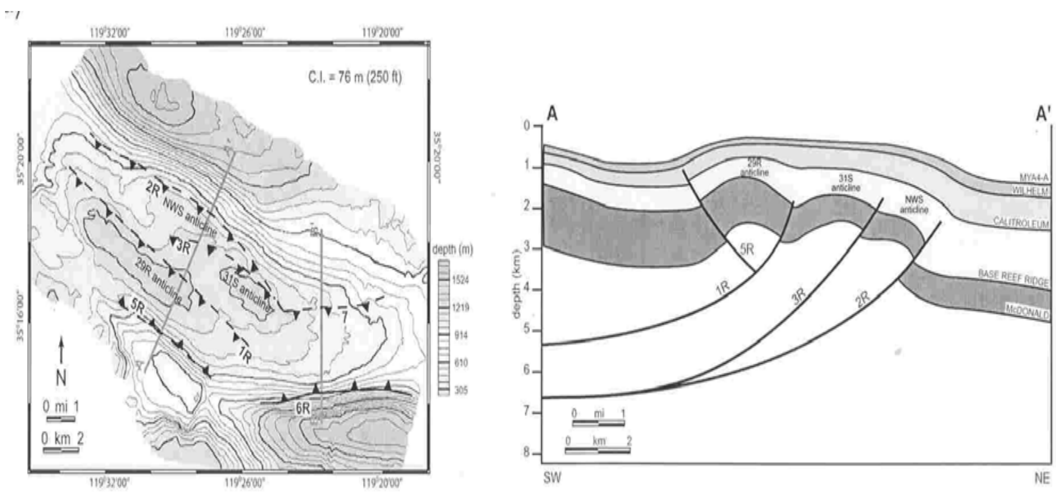
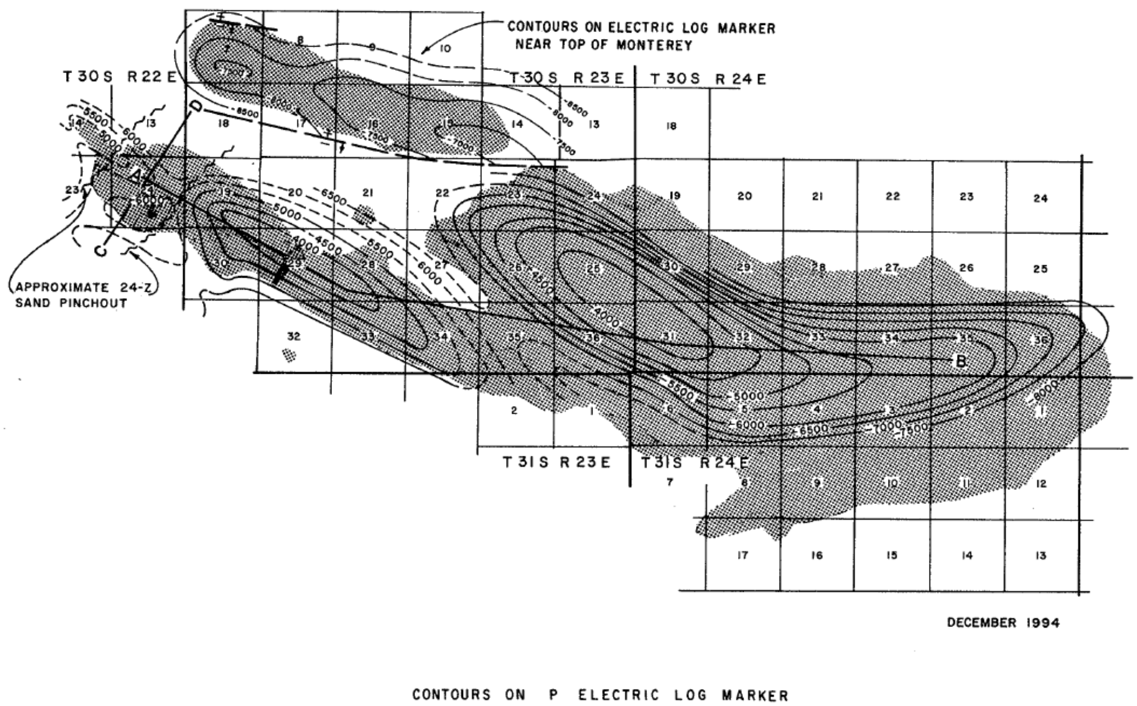


Figure 4: Elk Hills Field structure contour map of upper Pliocene rocks showing faults and location of cross section A-A'; cross section A-A' showing structure of Elk Hills Field anticlines. (Fiore, et al. 2007)



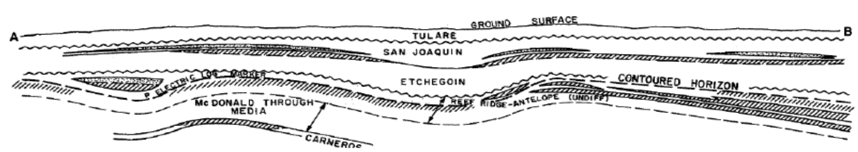


Figure 5: Elk Hills Field structure contour map of the upper Miocene and locations of cross sections A-B and C-D, below (DOGGR 1998)

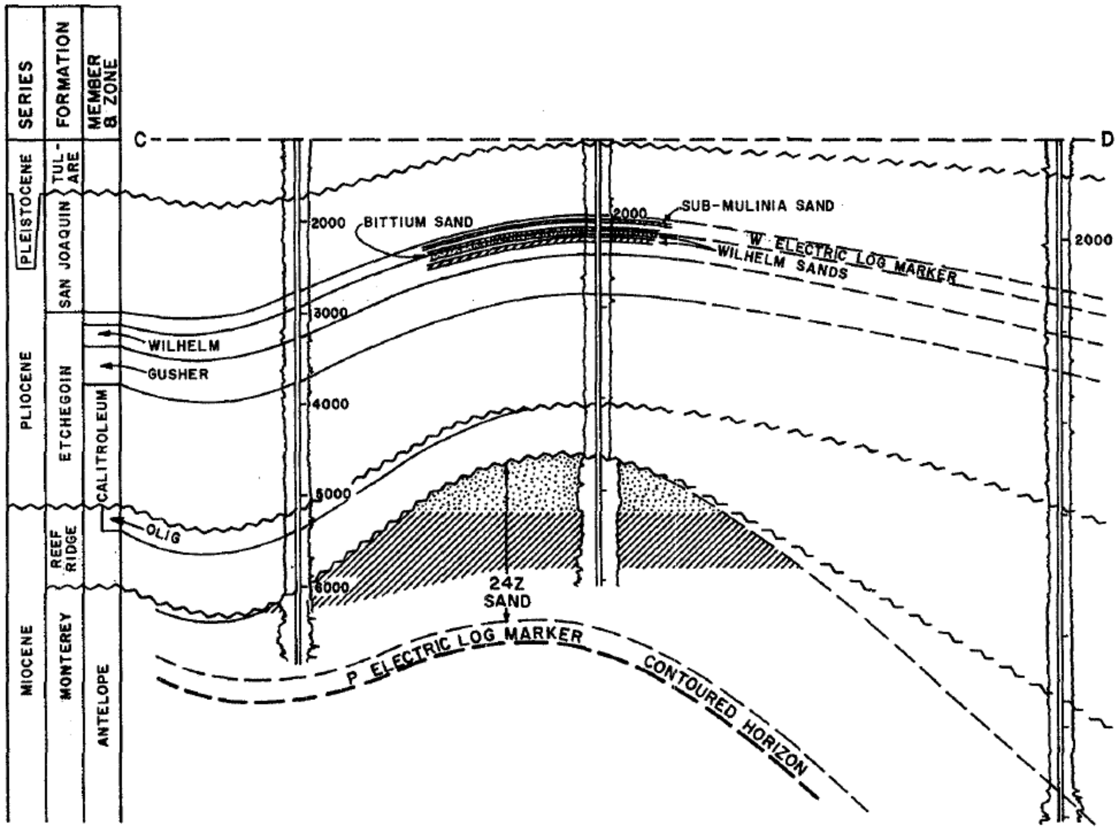


Figure 6: Elk Hills Field cross sections A-B and C-D; location shown in Figure 4 (DOGGR 1998).

To date, there have been more than 6,000 wells drilled to various depths within the Elk Hills Field, which provide an extensive stratigraphic database. The deepest well in the field is the 934-29R, drilled to a total depth of 24,426 feet, bottoming in Mesozoic, Upper Cretaceous age sediments. A schematic diagram of Elk Hills Field area stratigraphy, based on this well is presented (Figure 7), as well as the electric log (Figure 8). The oldest rocks drilled in the field are upper Cretaceous in age but are not productive. The Miocene aged Carneros sandstone member of the Temblor Formation is the lowermost oil producing interval in the field, although oil and gas shows have been recorded in deeper Oligocene and Eocene aged sediments. Above the Temblor is the Miocene aged Monterey Formation.

The Monterey (~ 4,500 to 10,000 feet deep) is known locally as the Elk Hills Field member and this formation includes the prolific Stevens oil sands that produce from stratigraphic-structural traps on three deep anticlines. Major Stevens reservoirs include Main Body B (“MBB”), 26R, W31S, 24Z, 2B, A1A6 and T&N pools. The Stevens sands are composed of stacked, fining upward turbidities, deposited as lenticular sheet sands, channels and levee deposits within a submarine fan complex (Reid 1990). Reservoir properties of the Stevens sands are excellent, with porosities averaging between 20 and 25 percent, permeabilities averaging 150 millidarcy (mD) and net reservoir thicknesses which can exceed 1,000 feet. The uppermost Miocene formation is the Reef Ridge Shale which is hard and siliceous (Nicholson 1990). A number of deep thrust and wrench faults, as well as a series of curvilinear normal faults intersect the

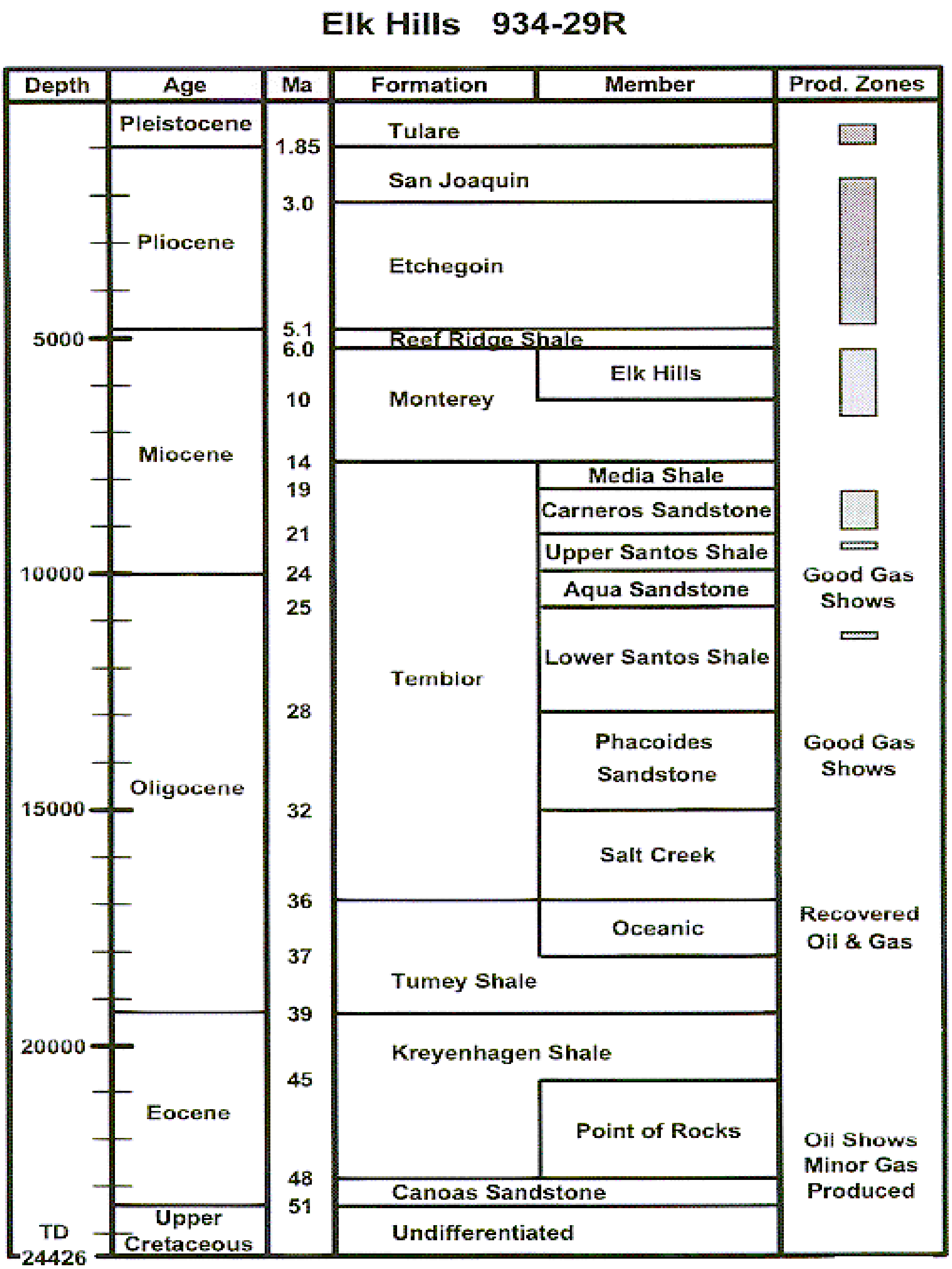


Figure 7: Elk Hills Field Stratigraphy Based on 934-29R Well (Nicholson 1990).

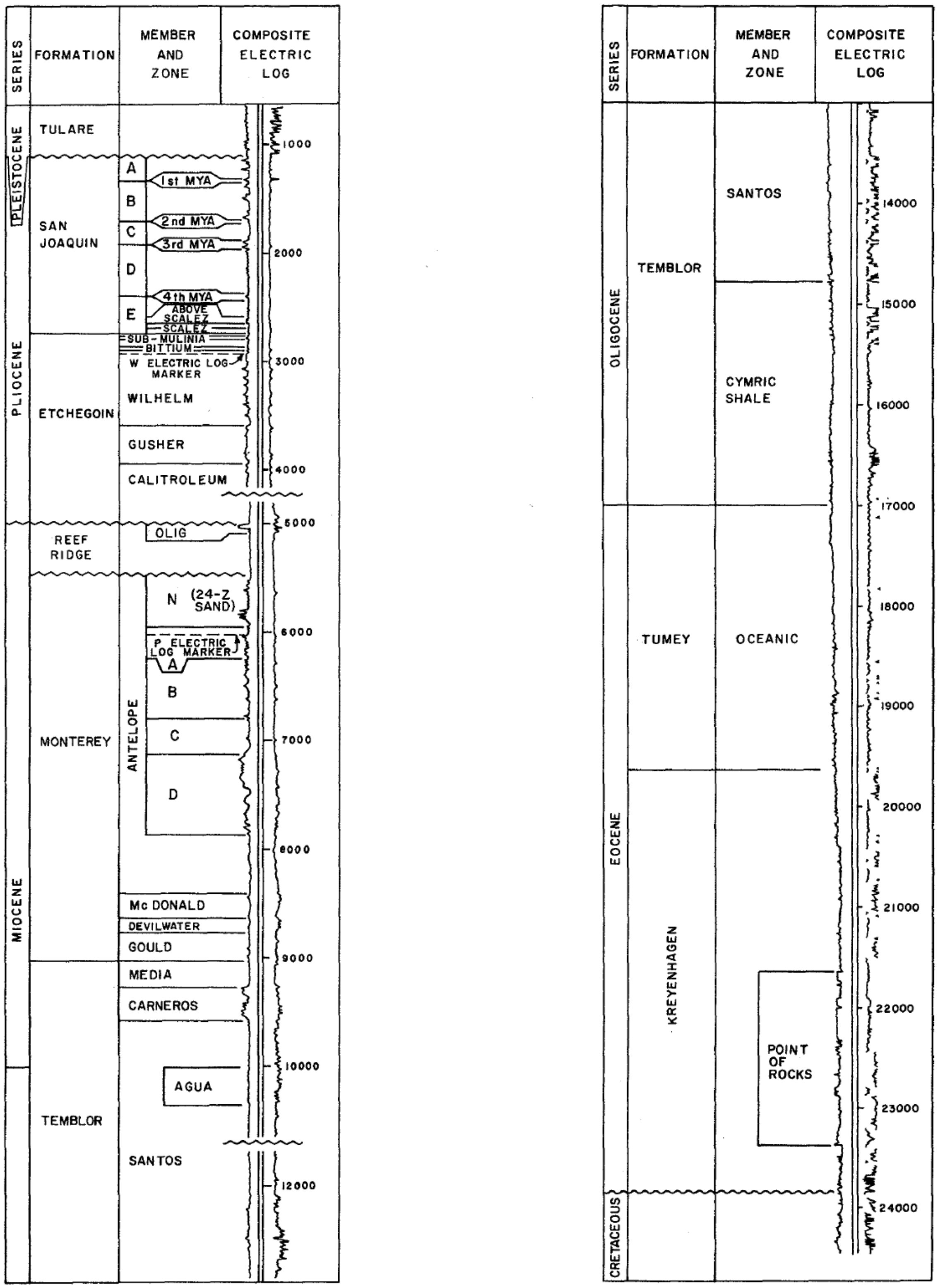


Figure 8: Elk Hills Field Stratigraphic Column (DOGGR 1998).

Stevens reservoir within the Elk Hills Field. These faults are believed to have influenced hydrocarbon migration from deeper source rocks (McJannet 1996), but faults within the productive limits on the anticlinal structures die-out in the overlying Reef Ridge and Lower Etchegoin Shales. These faults may provide some limited communication between some of the productive sands though most units are not in communication with one another, having different oil-water contacts. Further, even within individual anticlines sands are compartmentalized, exhibiting different pressures and temperatures (C&C Resources 2000).

Overlying the Miocene is the Pliocene Etchegoin Formation, which includes several productive silty and sandy members (Calitroleum, Gusher, Wilhelm, Bittium and Sub-Mulinia) and intervening shales, and above that the San Joaquin formation, which includes the productive, basal Scalez sand member and overlying shales (Figures 6 and 8). These Pliocene rocks represent a transition from deep water to shallow, near shore deposition. Isotopic analysis of these Pliocene oils suggests a separate Miocene source facies for these reservoirs and not simply vertical leakage from the older Miocene Stevens reservoirs (Zumberger et al 2005). The Pleistocene Tulare Formation is uppermost (0 to 1,500 feet.) in the Elk Hills Field and is comprised of fluvial and alluvial sediments (Nicholson 1990). The shallow Pliocene and Pleistocene section is cut by several shallow listric faults, some of which are sealing, but these faults do not traverse through the Reef Ridge Shale and do not extend into the deeper Stevens reservoir (C&C Reservoirs 2000).

In summary, the structure and stratigraphy of Elk Hills Field is ideally suited for the injection and long-term sequestration of CO_2. The CO_2 injection zone – MBB – and other targeted CO_2 injection zones are within the Stevens reservoir. The Stevens reservoirs are porous, permeable and can be very thick, providing an excellent CO_2-EOR target and ample pore space for long-term CO_2 sequestration. The overlying shales are excellent seals and have proven capable of containing water-buoyant fluids and gasses for millions of years. While faults are present within the Elk Hills Field, these faults are non-transmissive as indicated by variable oil-water contacts, pressures and temperatures within individual Stevens reservoirs. Furthermore, there are several productive horizons above the proposed injection zone within the Pliocene Etchegoin and San Joaquin formations (~ 1,500 to 4,000 feet deep.), but isotopic evidence shows that the shallow Pliocene oils are not the result of simple vertical leakage from the deeper Miocene Stevens reservoirs. Consequently, there is essentially no risk of CO_2 leakage to the surface or to the atmosphere from the targeted CO_2 injection zones at Elk Hills Field.

CO_2 EOR and Sequestration at the Elk Hills Field

The Stevens reservoirs are considered the best CO_2 EOR targets within Elk Hills Field. These reservoirs have been developed on 10- to 40-acre spacing and have produced in excess of 580 million barrels of oil (mmbo) to date. Reservoir pressure in the MBB sand is near the minimum miscibility pressure of approximately 2,415 pounds per square inch (psi) (D. Merchant 2006), indicating this reservoir is an ideal candidate for miscible-CO_2 EOR[4]. By analog, documented West Texas miscible-CO_2 EOR's have produced an incremental 10 to 20 percent of

[4] As noted earlier, miscibility is a property of CO_2 to completely mix with oil, which lowers the viscosity of the oil and allows more of it to be produced. The minimum miscibility pressure is the lowest reservoir pressure where complete mixing can occur.

oil, on average (Holtz et al. 2005). This range is also consistent with a CO_2 EOR pilot study in the Stevens sand at North Coles Levee field 2 miles east of Elk Hills Field conducted by ARCO (MacAllister 1989). The MBB reservoir represent only a subset of the target Stevens reservoirs currently suitable for miscible-CO_2 EOR.

The Stevens MBB reservoir has an average thickness of 450 feet, 20 percent average porosity and 32.2 mD geometric mean permeability (C&C Reservoirs 2000). The current development is a mature pattern water flood with over 150 water injection wells and an average injection rate near 1,000 barrels water per day (bwpd). OEHI proposes to convert the reservoirs from water flood to a miscible-CO_2 EOR flood. During this process, many of the water injectors will be converted to CO_2 injectors, with estimated average injection rates between 2 and 10 mmscf/d.

In summary, EOR with CO_2 in the targeted CO_2 injection zones of the Stevens reservoirs has the potential to significantly increase oil reserves and extend the productive life of the Elk Hills Field. There is adequate capacity within the Stevens reservoirs to support the volume of CO_2 that will be generated by the HECA Project. The operational injection volume and pressure will be reviewed as a part of OEHI's review process with DOGGR.

SEISMICITY

In the context of CO_2 sequestration, it is important as part of site selection to understand the risks of potential CO_2 leakage from the reservoirs due to seismicity. These risks are generally twofold—one is induced seismicity from injection activities and the other is any increased leakage risk due to natural seismic activity. The HECA Project evaluated both of these concerns with respect to the Elk Hills Field. The results are set forth below.

Induced Seismicity and Potential Impacts

In 2008, the HECA Project conducted a regional seismicity study for the Elk Hills Field. Even with decades of fluid injection for EOR, there is no public record of measurable induced seismicity at Elk Hills. The Elk Hills Field contains significant volumes of gas in place and is currently undergoing significant water and gas injection operations. The study found that the risk of induced seismicity due to CO_2 injection operations was remote and highly unlikely (Terralog Technologies 2008).

Furthermore, even in the unlikely case of an induced seismic event, any such seismic event would likely be less than magnitude 4, based on the geologic setting, areal extent and depth of proposed operations, and anticipated pressure and stress changes (Terralog Technologies 2008). Seismic events on the order of magnitude 3 to 4 may be felt within the immediate area (approximately 1 kilometer [km]), but would not be expected to cause structural damage to facilities or buildings for the following reasons. Most surface structures near the Elk Hills Field are likely to be at distances from about 6 to 30 miles (10 km to 50 km) from the epicenter of any induced seismic event. Assuming a highly unlikely scenario, which is potentially induced seismicity up to magnitude 4 located at a depth of about 6 miles (10 km), the induced horizontal ground acceleration would be on the order of 0.01 g, which is an order of magnitude lower than the California seismic codes (Figure 9). Seismic codes in California require structures to withstand horizontal acceleration in excess of 0.1 g, with varying strength depending on the

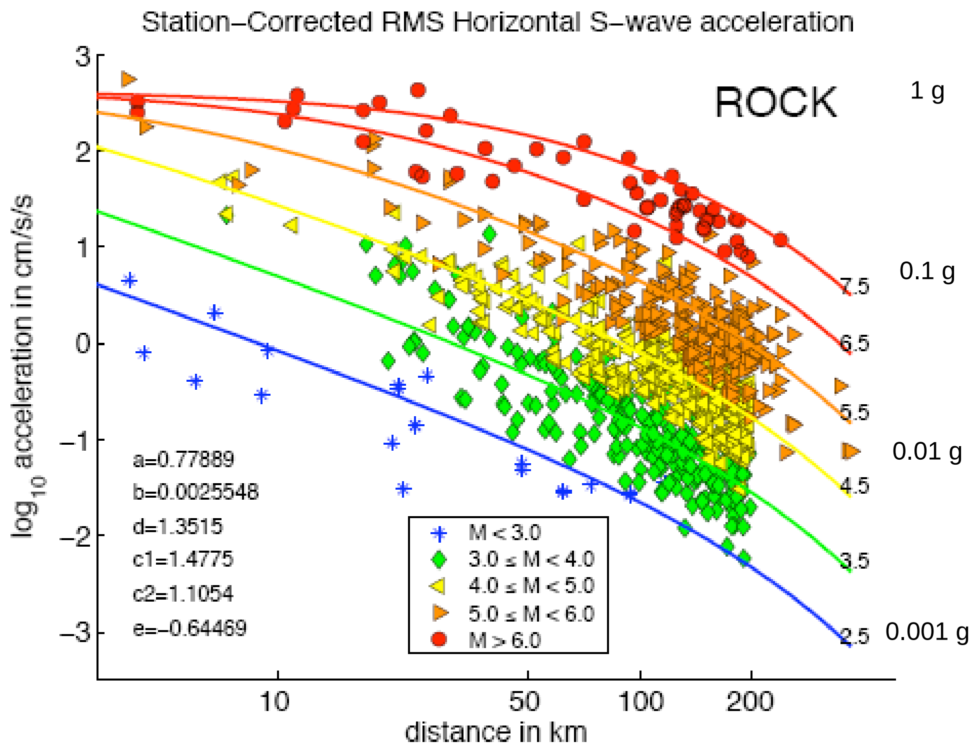


Figure 9: Relation of horizontal ground acceleration to seismic magnitudes based on 70 earthquakes in the Southern California Region (G.B. Cua 2005).

seismic zone location and the use of the structure. Therefore, even with the assumption of an induced seismic event, there is minimal risk that any damage would result to surface structures. This magnitude induced seismicity also would not cause any damage to injection equipment or the reservoirs, as detailed in the following section.

Naturally Occurring Seismicity and Potential Impacts

Since 1990, there have been 129 naturally occurring earthquakes recorded with a magnitude greater than 3.0 within a 60 mi (100 km) radius of Elk Hills (Figure 10). The vast majority of these have occurred along the White-Wolf fault, approximately 30 miles southeast of Elk Hills (Southern California Earthquake Data Center web site). The Elk Hills Field is situated about 15 miles east of the San Andreas Fault.

The seismic study found that natural seismicity of magnitude 3 to 6 is not likely to impact field operations and is highly unlikely to lead to leakage of any injected CO_2 from the Elk Hills Field. This assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the injection project, which is (in relatively soft and shallow (~ 6,000 feet) sediments. Most major earthquakes magnitude 6 and above in California occur at depths of 6 miles or more in brittle basement rock, while the proposed injection reservoirs at Elk Hills Field is less than 2 miles deep in relatively soft sandstone. The strength of seismic waves decreases with distance, therefore the large separation between major earthquake source and injection reservoirs would help prevent well damage (W. Foxall and J. Friedmann 2008).

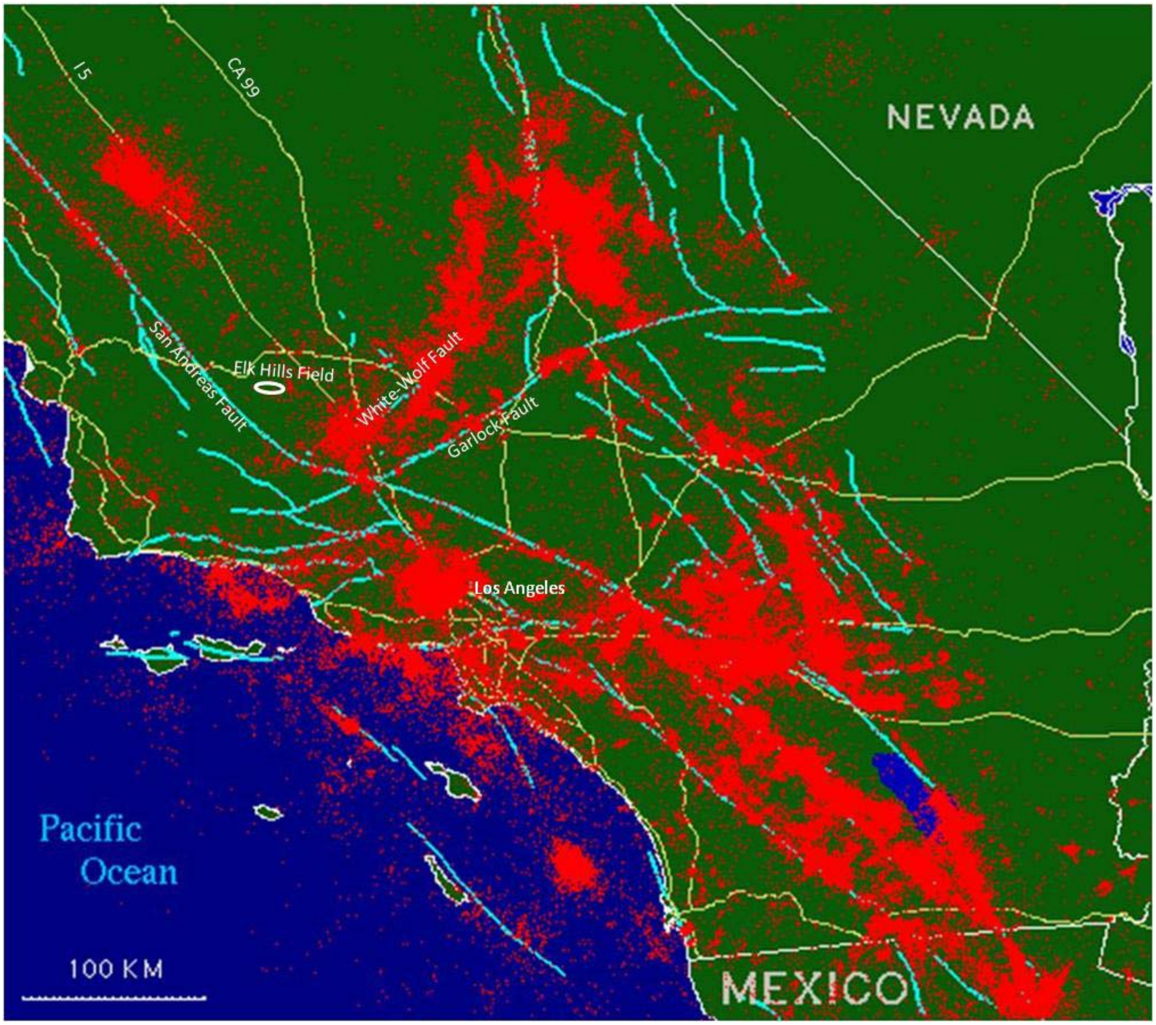


Figure 10: Seismic events in Southern California from 1932 to 1996 (Southern California Earthquake Data Center)

The southern San Joaquin Valley area is a very prolific oil and gas producing region, with 100 years of production (and associated water/gas/steam injection operations) from about 70 oil and gas fields. There are more than 58,000 production and injection wells in Kern and Inyo counties. These existing wells have experienced decades of seismic activity with no harmful release of gas, oil or water to the surface during earthquakes. This is primarily due to the fact that metal casings on wells merely deform slightly under seismic strains, rather than break.

The nearby Los Angeles Basin, which contains more than 80 oil and gas fields (with more than 24,000 production and injection wells) and several natural gas storage fields, is even more seismically active than the southern San Joaquin Basin. From 1998 to 2008, more than 400 earthquakes greater than magnitude 3.0 were recorded within 100 miles of Los Angeles (Southern California Earthquake Data Center). During the operational life of these wells, the LA Basin has experienced more than twenty major earthquakes (greater than magnitude 6), some directly adjacent to major gas fields and natural gas storage fields, with no harmful release of gas to the surface. Natural gas is, of course, a far more hazardous substance than CO_2, yet gas storage fields have been permitted and have been safely operating for more than 50 years in the Los Angeles Basin, despite its history of significant seismic activity.

For example, the magnitude 6.7 Northridge Earthquake of 1994 occurred almost directly beneath (within 10 km) the Aliso Canyon Gas Storage Field, which stores more than 100 billion cubic feet of natural gas for the metropolitan Los Angeles Area (Figure 11). The main quake occurred at a depth of almost 18 km, and several aftershocks up to magnitude 3 were scattered within the field itself at typical well depths, as shown in Figure 12 below. There was no gas leakage and no significant well problems from this event. Only one out of 400 wells was deformed slightly, and there was no gas release. Natural seismic events on the order of magnitude 6 and smaller, even if located in the immediate area of the Elk Hills Field, should not cause significant damage to wells or lead to leakage of injected CO_2.

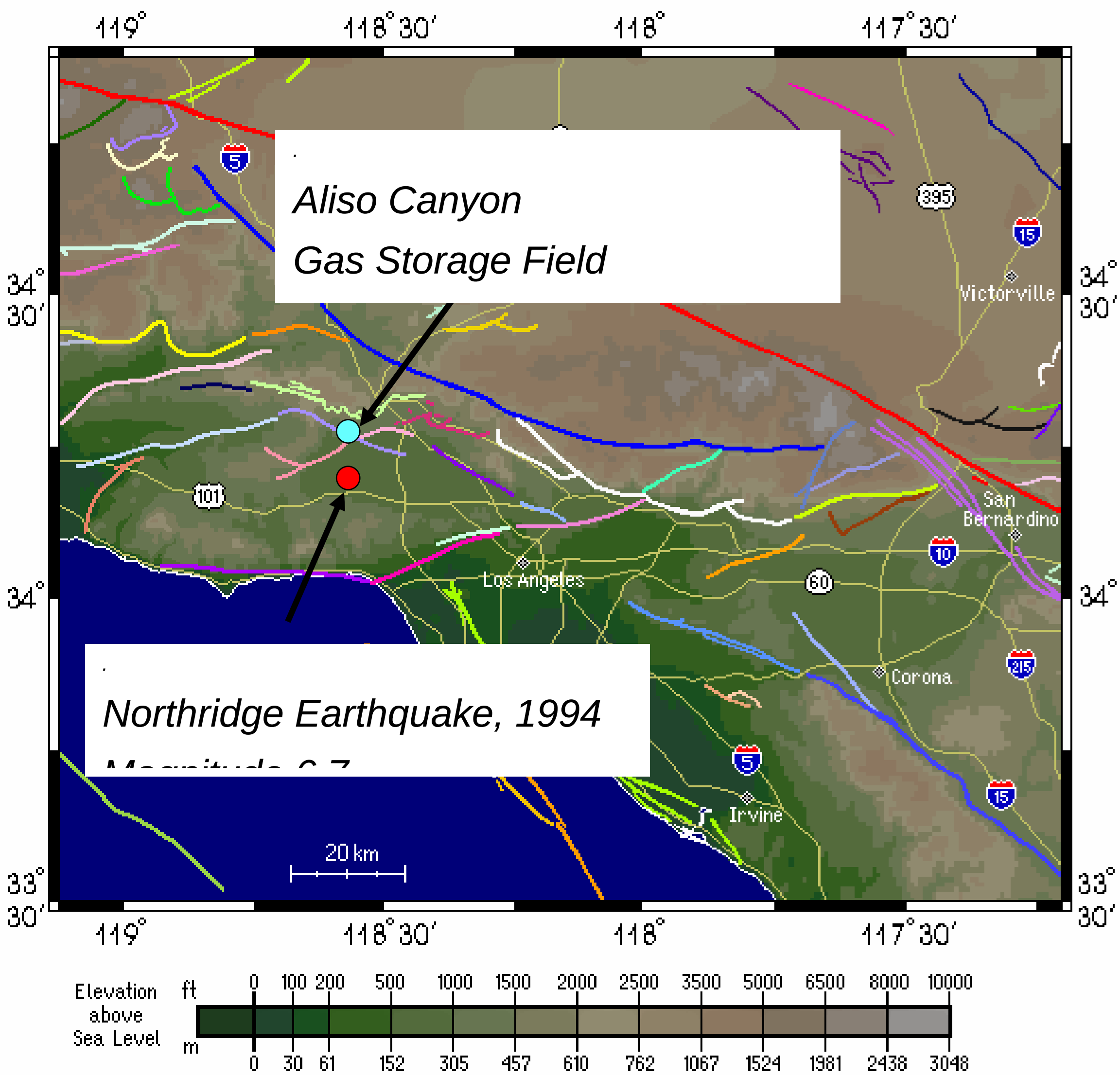


Figure 11: Approximate location of the Aliso Canyon gas storage field and the epicenter of the Northridge earthquake (Southern California Earthquake Center).

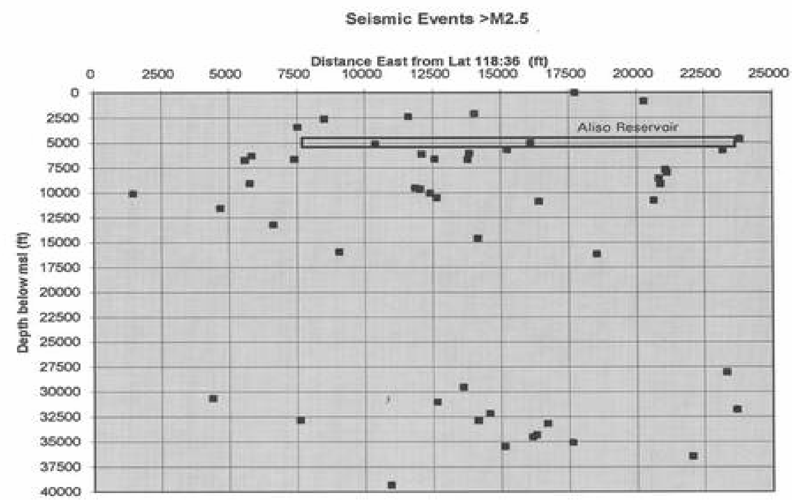


Figure 12: Depth of aftershocks from the 1994 Northridge earthquake in relation to the Aliso Canyon gas storage field (Terralog Technologies 2008).

In summary, the risk of induced seismicity from CO_2 EOR and Sequestration is remote. Moreover, even in the unlikely event of induced seismicity, the predicted magnitude would be no greater than 4.0. This type of event (4.0 magnitude) is comparable to the existing natural seismicity in the Elk Hills Field area and, as discussed above, would not cause structural damage to surface facilities in the nearby area. With respect to natural seismic events, there is abundant historic data and information demonstrating that a rather significant seismic event (on the order of magnitude 6), even if located in the immediate area of the Elk Hills Field, should not cause significant damage to wells or lead to leakage of injected $CO_{2.}$ Finally, due to the numerous shale-sealed formations above the target injection zone, any vertical gas migration that might occur from the injection interval would be contained and not reach the surface.

Elk Hills Field Development and Production History

Part of the site selection analysis involves a detailed review of the development history of the potential site to determine if the reservoirs will provide secure containment. The Elk Hills Field was officially discovered in 1919, although there had been production as early as 1911. Associated Oil Company's well #1 encountered oil in the Pliocene Upper Calitroleum Member at a total depth of 4,030 feet. The Elk Hills Field was part of the U.S. Naval Petroleum Reserve system, created in 1912. Some shallow drilling occurred in the 1920s to develop the Pliocene, but the deeper Miocene Oil was not discovered until 1941 and little development occurred in the field until the 1970s. Full commercial development did not begin until 1976 under the Naval Petroleum Reserves Production Act. In 1996, Congress authorized privatization of the Elk Hills reserve, and in 1998 OEHI, a subsidiary of Occidental Petroleum Corporation ("Occidental"), acquired the U.S. government's interest in the field and became its operator.

Active development of the prolific Stevens reservoirs did not begin until 1976, resulting in a relatively modern well stock and a detailed and thorough data set of injection zone well penetrations. With drilling at the level of the injection zone occurring only recently (post-1975), OEHI has a complete database of injection zone well penetrations and completions. This existing information identifies and locates all wells within the confining zone. This thorough database provides ample data and information to confirm the secure containment of the field. Also, this information greatly reduces the risk of leakage due to unknown or improperly completed well penetrations, which is generally recognized as the main risk associated with utilization of oil fields for CO_2 sequestration.

OPERATIONS[5]

Operator Qualifications

One of the critical components in a successful CO_2-EOR and sequestration project is effective field operation. Maintaining (i) efficient production and injection operations (at pressures that will not damage the confining zone), (ii) the mechanical integrity of all equipment, and (iii) compliance with all applicable regulations, will result in safe and reliable operations. Occidental is one of the largest and most respected CO_2-EOR operators in the world and is the largest oil producer in the West Texas Permian Basin, operating over 20 CO_2-EOR projects. Occidental has proven operational competence and a stated focus on enhancing recovery in mature fields through the use of advanced technologies in such areas as reservoir description and modeling; well construction; field automation, artificial lift technology and well and equipment maintenance.

Field Development

CO_2 EOR and Sequestration will focus on the Stevens reservoirs. These reservoirs have been under peripheral and pattern waterflood for more than 35 years. Reservoir pressure in the target reservoirs currently exceeds the estimated minimum miscibility pressure. Much of the injected CO_2 will circulate through the reservoir and be produced from offset production wells along with oil and gas. The produced CO_2 will be separated from the sales streams and re-injected into the reservoir. This recycled CO_2 volume will be utilized to expand the pattern EOR development across the field.

Injection Operations

Field development will consist of a pattern flood, operated under water-alternating-gas/ CO_2 (WAG) injection design. Injection wells will be equipped to switch between water and CO_2 injection at any time. Alternating between water and CO_2 (gas) injection will improve sweep performance of the EOR operation and help California fully develop its natural hydrocarbon

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[5] The following general information in this section has been provided by OEHI. OEHI will comply with all applicable DOGGR requirements for CO_2 EOR and Sequestration.

resources. WAG injection wells will be operated in a manner similar to existing water injection wells. As such, all existing safety and environmental standards will be continued. The CO_2 EOR and Sequestration will generally use the equipment described below. The equipment used within this facility will form an enclosed system designed to inject, separate and reinject CO_2. The following paragraphs discuss the equipment used in a typical CO_2-EOR project.

Production Wellheads

Several types of production wellheads are employed in a CO_2 flood, depending on the type of lift that is placed on a production well. The methods of lift employed are (1) beam pumps, (2) electric submersible pumps (ESPs), and (3) naturally flowing the well. The specific lift depends on fluid volume and the gas-to-liquid ratio. Each well is equipped with a separate production flowline.

Beam Unit Wellhead Configuration: Standard materials, designed for CO_2 service, are used within the wellhead. Blowout prevention systems (BOPs) are installed to shut down the well if there is leak. Beam pumped wells are equipped with pump off controllers (POCS) to permit remote starting and stopping and a central computerized alarm and shutdown system.

ESP Wellhead Configuration: The wellhead assembly commonly has at least a 2,000 psi working pressure and the surface casing is extended to ground level. The flowline is monitored for high and low pressure and includes a high pressure shutdown switch. ESP wells are equipped with computerized monitoring and alarms and to permit them to be remotely started and stopped.

Flowing Wellhead Configuration: The wellhead is typically certified to a 3,000 psi working pressure. Flowing wells equipped with computerized monitoring and alarms and to permit them to be remotely started and stopped.

Production Flowlines

Production flowlines in a CO_2 flood are typically made of API grade carbon steel pipe tested to verify compliance with the specification. Each flowline is protected by a high pressure shutdown switch and by shared relief valves on the automatic well test headers.

Production Satellites

A production satellite consists of the following major equipment:

- Automatic well test header
- Test and production separators (oil/gas/liquid)
- Production Programmable Logic Controllers (PLCs) and automation

Automatic Well Test Header: Well testing consists of temporarily routing each well to a test separator where the three phases (oil, gas, and water) are separated and then measured for production rates. The production header and test header are each protected by a relief valve as well as a pressure transmitter that relays a high pressure alarm to the supervisory control and data acquisition (SCADA) system.

Test Separators: The test separator is a horizontal three-phase vessel where oil, produced water, and produced gas are measured. Following measurement, the oil, produced water, and produced gas are recombined and routed back to the production header. The test separator is protected by a pneumatic inlet shutdown valve that closes on high fluid level, low fluid level, and high pressure. There are redundant loops for the vessel alarms.

Production Separators: The production separator incorporates the same measurement devices, control valves, alarms and safety devices as on the test separator.

Production PLCs: The production PLC controls the entire production side of the satellite battery and is capable of performing automatic well testing for typically up to 30 producing wells. The PLC performs all the alarm and shutdown functions at the satellite. The PLC also sends the alarm and shutdown information to the centrally located host computer. The production PLC and the automation system have an uninterruptible power supply (UPS) system that will operate for a minimum of four hours in the event of a power failure.

Central Tank Battery (CTB)

A central tank battery typically used in a CO_2 flood consists of the following major equipment:

- Two phase inlet separator
- Flume
- Gunbarrel tank
- Oil and water storage tanks
- Water injection pumps

Inlet Separator: The inlet separator receives produced fluid from the satellite battery production separators. Due to the pressure differential between the production separators and the inlet separator, produced gas is liberated from the produced fluid. The inlet separator is equipped with the same level control, pressure control, measurement, inlet shutdown valves, and safety devices as the production separator. However, one distinct difference is that the inlet separator is also equipped with an inlet flow control valve that dampens flow rate spikes due to two phase flow regime slugging caused by the produced gas being liberated from the produced fluid in the liquid gathering system..

Flume and Gunbarrel Tank: The flume is located directly upstream of the gunbarrel tank and is used to separate the gas that breaks out from the produced fluid stream due to the pressure drop from the inlet separator. The flume separates the gas and fluid. The separated gas flows from the top of the flume to a connection on top of the gunbarrel tank. The gas-free fluid flows from the bottom of the flume to gunbarrel tank for gravity separation of the oil and water. As the oil level in the tank rises, it flows to the oil sales tank. The water leaving the gunbarrel tank flows to the water tank.

Oil and Water Storage Tanks: All tanks are equipped with emergency vents that comply with API 2000 standards. All steel tank bottoms are protected with cathodic protection. The gunbarrel tanks and water tanks are protected against corrosion from coating failures. The tanks are connected together by a common overhead vent system that is equipped with a pressure control valve.

Water Injection Pumps: Electric-driven centrifugal pumps take suction from the water tanks and discharge into the water injection system.

Re-Injection Compression Facility (RCF)

Re-injection compression facilities typically consists of the following major equipment:

- Inlet manifold
- Inlet slug catcher
- Glycol contactor and dehydration system
- CO_2 and Hydrocarbon Separation Unit
- Re-injection compression

Inlet Manifold: The RCF inlet manifold is the terminus of the produced gas gathering system. Each incoming gas gathering system trunk line is equipped with a pressure shutdown switch. Gas from the inlet manifold flows to the inlet slug catcher.

Inlet Slug Catcher: The purpose of the inlet slug catcher is to remove any liquid carryover from the produced gas gathering system.

Glycol Contactor: The triethylene glycol contactor is outfitted with structured packing to promote glycol/gas exchange. The glycol is regenerated in the glycol reboiler.

CO_2 and Hydrocarbon Separation Unit: The unit recovers the CO_2 and gaseous hydrocarbons that are produced. The process includes bulk CO_2 separation followed by final CO_2 removal from hydrocarbon gas. The CO_2 free hydrocarbon gas is then transferred to existing gas plants where the products include sales gas, propane, butane and natural gasoline. The separated CO_2 is reinjected into the reservoir.

Re-injection Compression: The produced gas inlet pressure to the re-injection compression system is set to minimize overall compression horsepower while maintaining an appropriate back pressure on the producing wells. The gas volume is measured and a gas chromatograph takes a sample of the gas leaving the re-injection compression facility. The data is sent to the central computer and relayed to the injection satellite PLCs where the gas composition data is used to calculate and control the injection well bottomhole pressure within specified limits. The total re-injection gas stream is then measured before being discharged into the produced gas re-injection trunk lines and ultimately re-injected into the reservoir. Each compression train is equipped with automatic control and safety shutdown systems.

Injection Satellites

Injection satellites are commonly co-located with the corresponding production satellite. Injection satellites consist of the following equipment:

- Injection trunk lines – produced gas/ CO_2 and produced water injection
- Water Alternating Gas (WAG) injection manifold
- WAG injection lines with fiber optic communications with injector wellheads
- CO_2 displacement pump
- Injection Control PLC

Injection Trunk Lines – Produced Gas/CO_2 and Produced Water Injection: Produced gas, CO_2 injection trunk lines and water injection trunk lines are constructed to American Society of Mechanical Engineers (ASME) B31.4 with a typical design pressure of 2,220 psig (ASME 900 Class). The water injection trunk lines are internally lined and are cathodically protected.

Water Alternating Gas (WAG) Injection Manifold: WAG injection manifolds consist of water injection header, produced gas/ CO_2 injection header, CO_2 displacement pump header, injection well meter runs and control systems.

WAG Injection Lines: The WAG injection line that connects the WAG manifold injection meter run to the injector wellhead is constructed to ASME B31.4 with a typical design pressure of 2,220 psig (ASME 900 Class). There is real time data transmission, monitoring and control between the injection satellite and the injection well. Each injector is equipped with a tubing pressure transmitter, tubing temperature transmitter, casing pressure transmitter, and an injection well site control panel.

CO_2 Displacement Pumps: CO_2 displacement pumps are typically an electric driven positive displacement triplex plunger pump. The pump takes suction from the water injection header and discharges to the CO_2 displacement pump header. The produced water is then pumped through the injection meter run and injection line to the injection well. The pump develops sufficient discharge pressure to displace the higher pressure produced gas or CO_2 from the injection line and injection tubing into the reservoir.

Injection Control PLC: Each injection satellite is equipped with an injection control PLC. The PLC performs the flow measurement calculations. Wellhead data monitored for each injection well includes injection tubing pressure, injection tubing temperature, and casing pressure. The wellhead data is transmitted back real time to the injection satellite. The PLC uses the WAG injection manifold data and wellhead data to calculate the bottomhole pressure for each injection well using Occidental’s patented bottomhole injection pressure algorithm (U.S. Patent No. 6,609,895 B2). The injection well can be controlled on flow rate, surface injection pressure, and bottomhole pressure for all three injectants – produced gas, CO_2 and produced water – using cascaded control loops. Injection well control using Occidental’s patented system maximizes reservoir processing rates by making it possible to adjust surface wellhead injection pressures on a real time basis to maintain a constant bottomhole pressure during CO_2 or water injection operations. The gas composition data from the chromatograph located at the Re-injection Compression Facility is used to calculate and control the injection well bottomhole pressure within specified limits. The PLCs will alarm or shutdown injection when operating parameters (e.g., pressure) reach preprogrammed setpoints

MONITORING, MEASUREMENT AND VERIFICATION

MMV is an integral part of the UIC permitting process pursuant to fluid injection and gas storage regulations required by DOGGR (Title 14 Chapter 4 of the California Code of Regulations). DOGGR has been delegated by U.S. EPA to administer the UIC program in California (Memorandum of Agreement between U.S. EPA and the California Division of Oil And Gas, 1981). The MMV requirements will achieve the key sequestration objectives: (1) ultimate containment of the stored CO_2; (2) protection of human health and the environment; (3) confirmation that the EOR project is behaving as planned; and (4) fulfillment of all applicable regulatory requirements.

MMV Approach for the Elk Hills Field

The site specific MMV Plan for the Elk Hills Field will include consideration of the existing detailed subsurface, seismic, geochemical and wellbore characterization that has been generated from the extensive data covering the field area. Selection of the appropriate suite of tools to fulfill the MMV goals (including the demonstration of CO_2 sequestration) will be based on an assessment of the potential risks taking into account the unique characteristics of the field and the performance expectations at the site, as agreed to by DOGGR.

There are several components that will be incorporated into the MMV Plan. OEHI's development plan for the Elk Hills Field, which includes injection of CO_2 for EOR, will be used to predict the field's future production over a period of many years. Reservoir characterization, which includes geologic modeling and petrophysical analysis, and simulation technologies will be used to develop reliable forecasts. Reservoir characterization and forecasting will be confirmed by applying the following:

- Monitoring of wellhead and annular pressures of all wells completed in EOR reservoirs, supplemented by downhole pressure and temperature where available.
- Monitoring of wellhead and annular pressures of wells completed in vertically adjacent reservoirs, supplemented by downhole pressure and temperature measurements in the offset reservoirs where available.
- Well integrity monitoring and cement evaluation.
- Material balance.
- Produced fluid geochemical sampling.

In connection with the foregoing, OEHI will supply any information requested by DOGGR to address the following:

- Subsurface data to characterize and represent in 3 dimensions the sedimentary section, structural geology and seismicity of the injection zone and overlying areas.

- Subsurface data to characterize and demonstrate that the injection zone is sufficiently porous to receive CO_2 under expected operating conditions and extensive enough to receive the anticipated volume of injectant.

- Subsurface data to characterize and demonstrate that the confining zone is sufficiently impervious to restrict vertical movement of CO_2 beyond the confining zone under expected operating conditions and extensive enough to contain the anticipated volume of injectant.

- Geomechanical data to characterize rock stress, rock strength and fault stability.

- Over the period that CO_2 injecting is occurring, geochemical data to characterize formation fluids in the injection zone and the lowermost porous unit above the confining zone.

- Over the period that CO_2 injection is occurring, well related injection data to allow physical and chemical characterization of injection fluids, including injection pressure, flow rate and temperature.

- Over the period that CO_2 injection is occurring, well related mechanical integrity data to demonstrate integrity of the wellbore and integrity of the vertical sealing capacity at the well site, such as regular mechanical integrity test results and other as may be required by permit.

The Elk Hills MMV Plan will demonstrate sequestration of the injected $CO_{2.}$

CLOSURE

The Closure phase of a CO_2 EOR and Sequestration project consists of site decommissioning, well plugging and abandonment, and appropriate post-injection site care and monitoring to demonstrate that the injected CO_2 is properly contained within the confinement zone and is not endangering human health or the environment. Site closure at the Elk Hills Field will be conducted pursuant to a post-injection site care and site closure plans that will be performance-based and specifically tailored for this field. The site will be closed upon demonstration of the following:

- Either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone.

- That based on the most recent geologic understanding of the site, including monitoring data and modeling, the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway.

- That wells at the site are not leaking and have maintained integrity.

CONCLUSION AND SUMMARY

The Project has completed an evaluation to prioritize and select appropriate CO_2 sequestration sites. The evaluations included a preliminary evaluation of North American basins, basin screening studies and detailed geotechnical (depth, seismicity, porosity, permeability, geochemistry, fault analysis, seal capacity) and engineering (pressure, miscibility, EOR potential, injectivity, mechanical integrity, infrastructure and operational requirements) analyses of high potential individual fields within select basins. This study was to assess their CO_2 storage capacity, containment and the viability for enhanced oil recovery projects. Based on these assessments, the Project identified the Elk Hills Field as one of the premier CO_2 EOR and Sequestration sites in the U.S. As described in this Appendix, analysis and study of the Elk Hills Field has confirmed that it is an optimal site for the safe and secure sequestration of CO_2.

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