

**ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)**

Elk Hills A1-A2 Storage Project

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO₂ geologic sequestration wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO₂ stored in the Monterey Formation at 0.25 - 0.75 million tonnes annually for 15 years with injection starting in 2025. The anthropogenic CO₂ will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

Director

Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

Deputy Secretary for Energy

Matt Baker: (916) 653-5356

Class VI - Wells used for Geologic Sequestration of CO₂

GSDT Submission - Project Background and Contact Information

GSDT Module: Project Information Tracking

Tab(s): General Information tab; Facility Information and Owner/Operator Information tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

Required project and facility details [40 CFR 146.82(a)(1)]

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

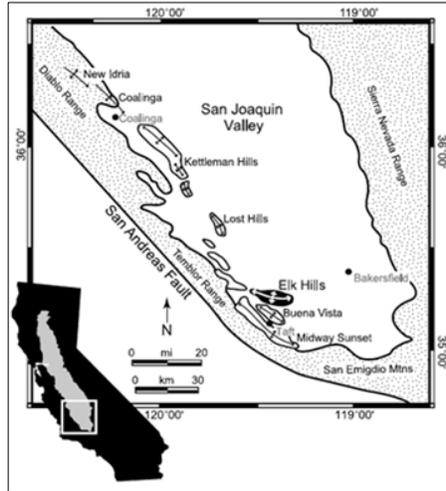
Discovered in the early 1900's the EHOFF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOFF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation A1-A2 sequestration reservoir was discovered in the 1970's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOFF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

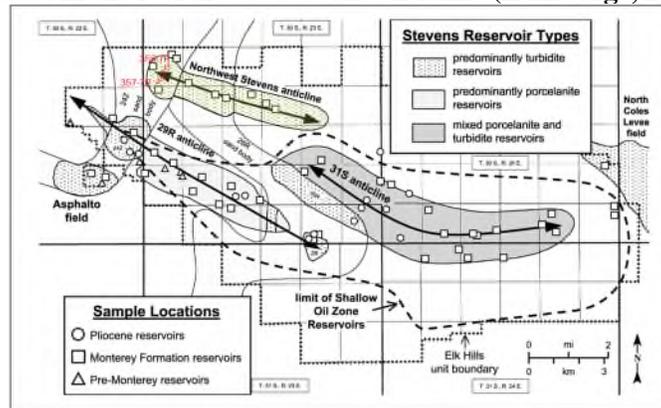
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



At the surface, the EHOFF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure subdivides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

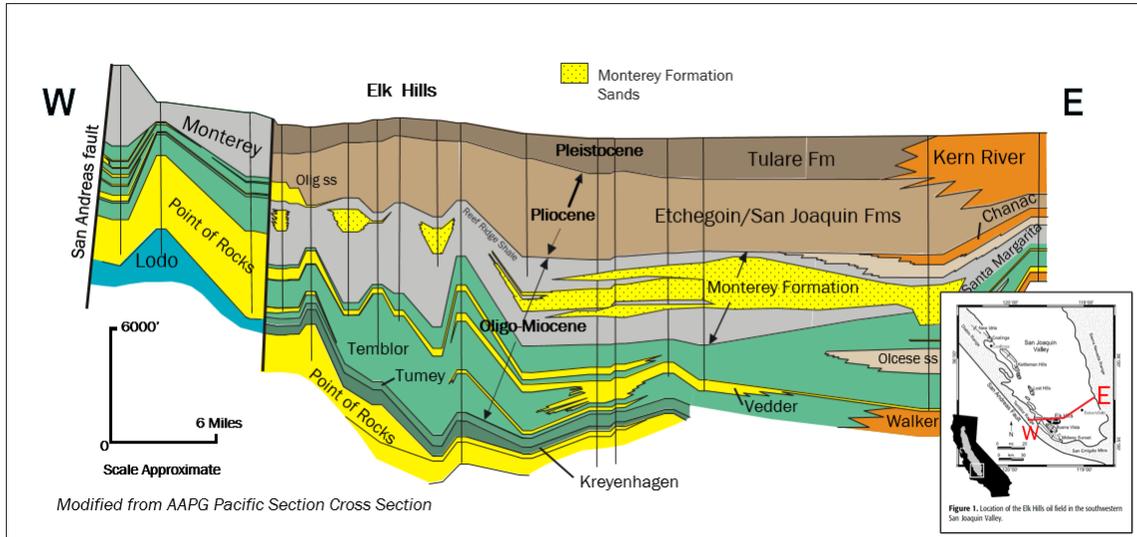
Figure 2: The EHOFF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation A1-A2 CO₂ sequestration reservoir is located in the Northwest Stevens anticline (Zumberge, 2005).



Geological Sequence

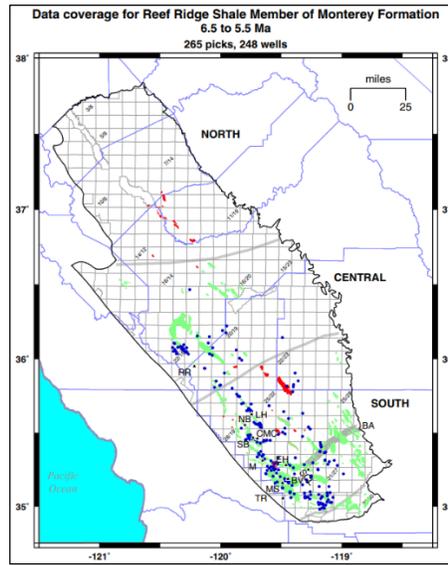
Figure 3 shows the stratigraphy of the EHOFF. The two injection wells will inject CO₂ into the Miocene aged Monterey Formation A1-A2 at the Northwest Stevens anticline approximately 8,500 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005). The storage reservoir for the project is the Monterey Formation and the confining shale is the overlying Reef Ridge Shale.



Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin (Figure 4) and serves as the primary confining layer for the Monterey Formation A1-A2 reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Figure 4: Reef Ridge Shale data coverage over the San Joaquin Basin (Hosford, 2007).

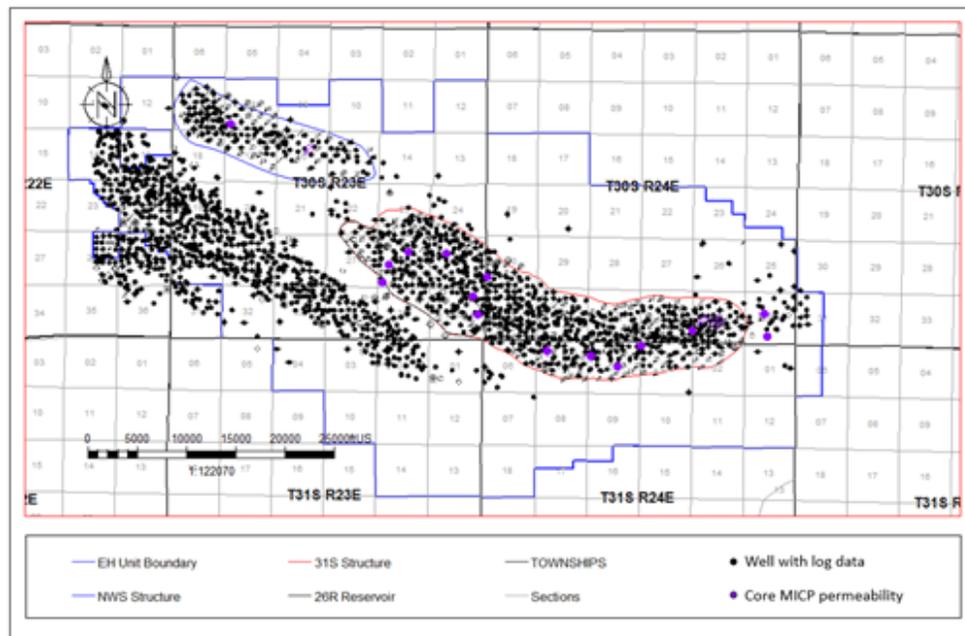


Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOV (Figure 5), creating an extensive library of information compiled within a comprehensive internal database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOV in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

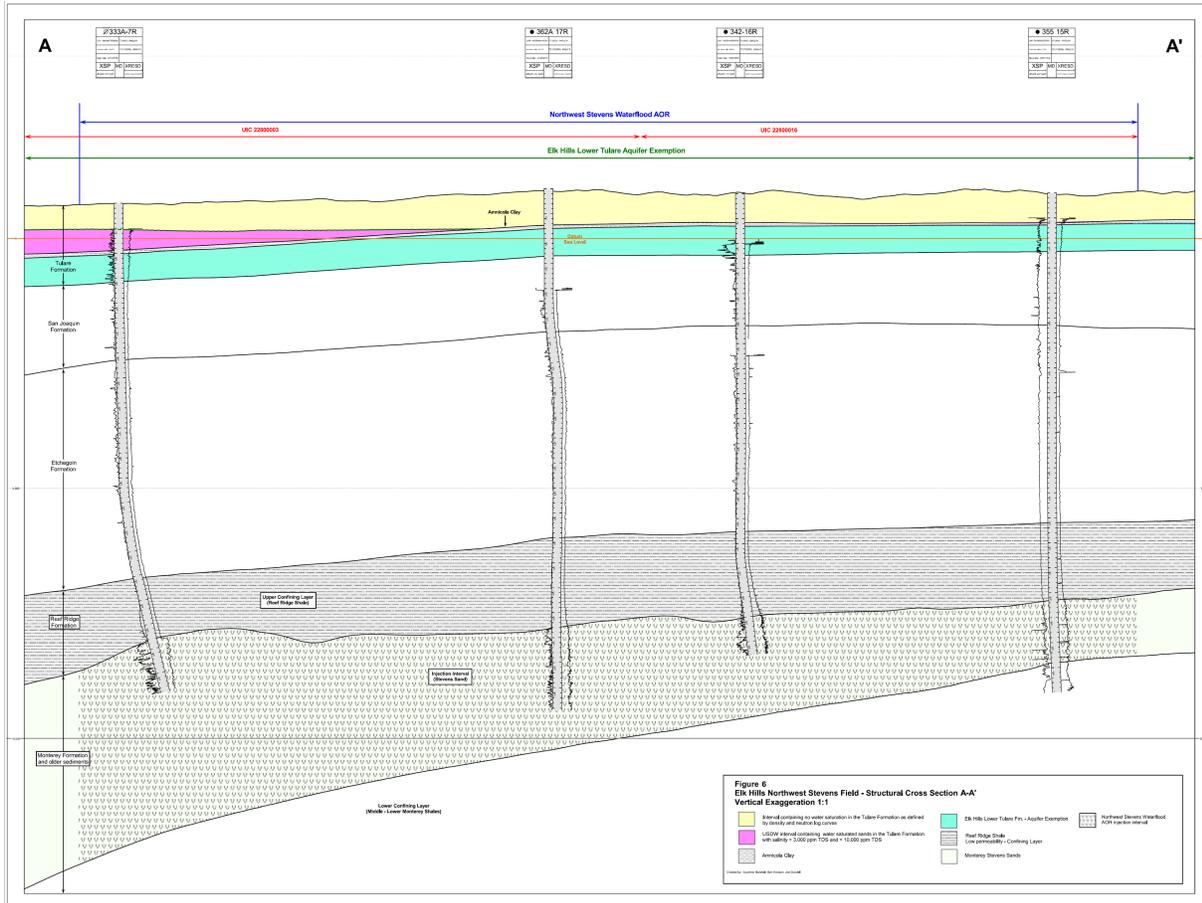
Figure 5: Wells drilled in the EHOV that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs that define structure and lithology of the storage reservoir and Reef Ridge confining layer. Wells with MICP core from the Monterey Formation are in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 6 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 6: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the Northwest Stevens anticline.



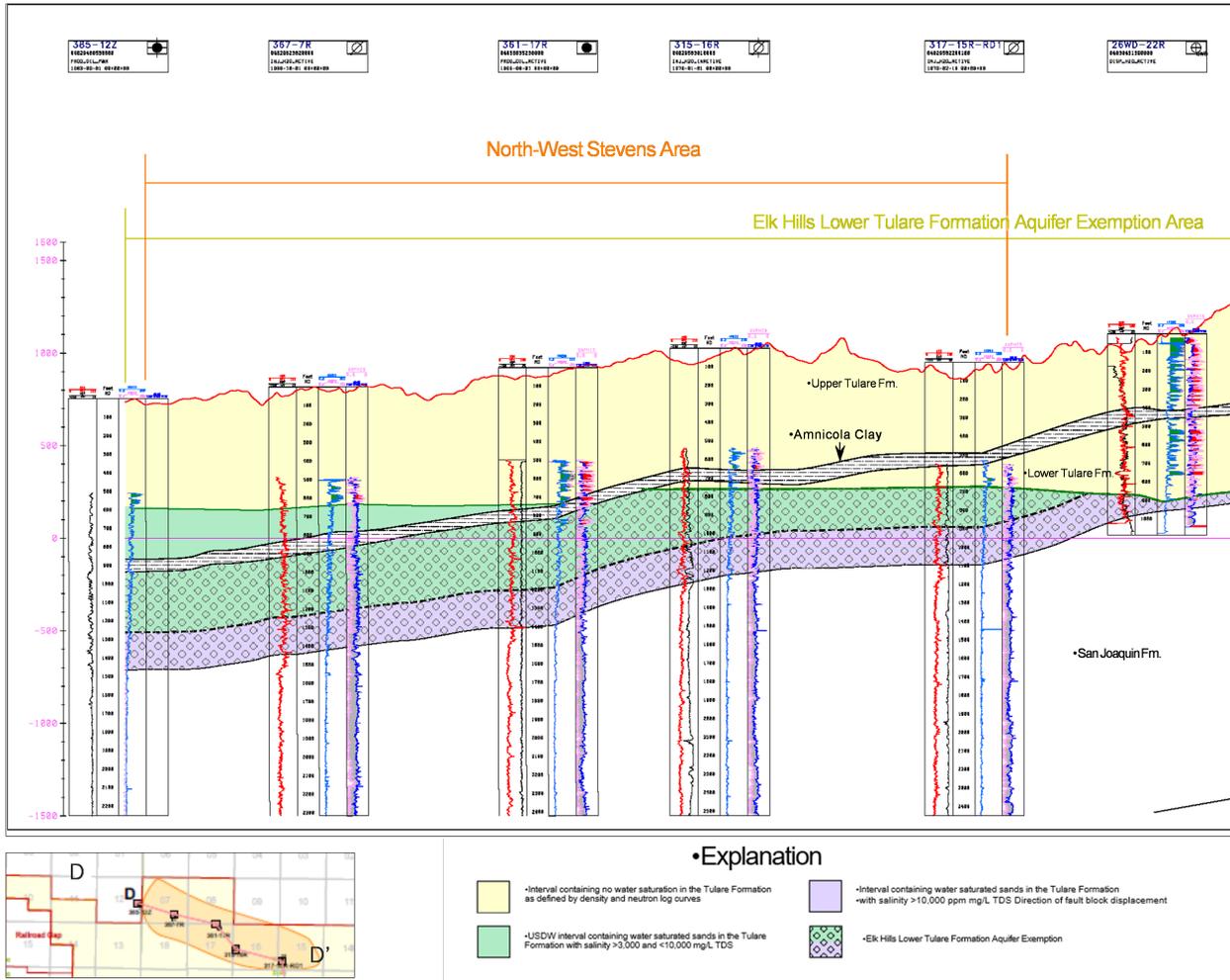
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 7), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOV and can be overlain by undifferentiated quaternary strata.

The Upper Tulare contains 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the only USDW in the AoR. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 7: The Tulare Formation consists of the Upper Tulare USDW and Lower Tulare and is separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer. The Upper Tulare USDW has formation water 3,000 - 10,000 mg/l TDS.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and

conglomerate of the Tulare Formation interfinger with the San Joaquin beds. The lower San Joaquin Formation conformably overlies the Etchegoin Formation and is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. Porous sands in the San Joaquin Formation will effectively dissipate possible CO₂ leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOFF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 - 37% porosity, 32 - 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below. Figure 6 shows a regional cross section, showing that the Etchegoin Formation is dominated by laterally continuous shales which limit hydraulic communication between sand lenses.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 6,929-7,962 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOFF the Reef Ridge Shale is continuous over the EHOFF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the Monterey Formation A1-A2 sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

The Monterey Formation A1-A2 sequestration zone is approximately 8,500 feet deep and produces 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.

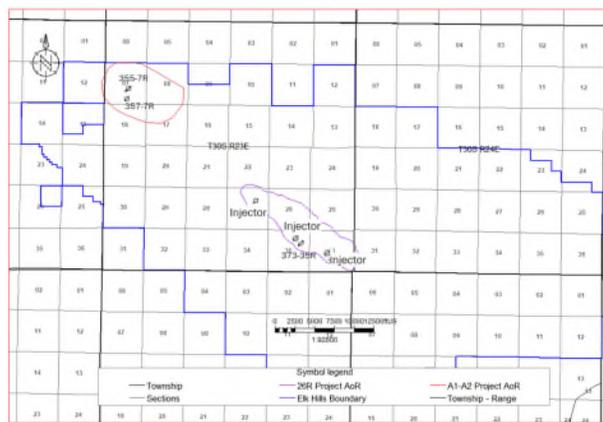
The Monterey Formation A1-A2 sands were deposited in two coalescing turbidite channels which were influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOFF. Figure 2 shows the orientation and depositional fairways for these channels in the Northwest

Stevens anticline. The sands were largely aggregational with minimal erosive deposition. At the base of the Monterey Formation is the Lower Antelope Shale Member, a stack of thinly bedded siliceous shale with interbedded sands.

The reservoir is continuous across the AoR and sands pinch-out on the channel edges. The Monterey Formation A1-A2 sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

The Monterey Formation will be developed with the Elk Hills A1-A2 and the Elk Hills 26R reservoir projects. The AoR and injectors for each project is shown in Figure 8.

Figure 8: AoR and injection well location map for Elk Hills A1-A2 project. The injection wells, 355-7R and 357-7R are 1,250 feet apart. Also shown is the Elk Hills 26R AOR and injection wells.



Underlying Monterey Formation A3-A11:

Underlying the Monterey A1-A2 Formation is the Monterey Formation A3-A11 reservoir. This stratigraphic package is not in communication with the A1-A2, as indicated by the following:

1. The two packages have been developed separately. The A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected).
2. The Monterey Formation A1-A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. This pressure differential is maintained due to hydraulic confinement between the two reservoirs. Pressure data obtained using Repeat Formation Testers (RFT) during the drilling of Oil & Gas wells in the project area has shown a clear separation in the pressure and pressure gradients in the A1-A2 reservoir in comparison to the A3-A11 reservoir. RFT data from two wells in the project area drilled in 2014 is shown below in Figure 10.

- The laterally continuous A2 shale separates the reservoirs (Figure 9). This shale is greater than 20 feet thick across the AoR and prevents communication between the Monterey Formation A1-A2 reservoir and the Monterey Formation A3-A11 reservoir.

The permeability function (Figure 19) is constrained with high clay content samples that enable the function to characterize the A2 shale permeability. Based on the 357-7R well, the A2 shale is 8900'-8920 feet in depth, 20 feet thick and has a permeability of 0.05 millidarcies. The derived permeability is shown in Figure 9.

Figure 9: 357-7R injector showing the Monterey Formation A1-A2 reservoir and the laterally continuous A2 Shale above the Monterey Formation A3-A11 reservoir. The depths shown are for feet subsea true vertical depth and feet measured depth.

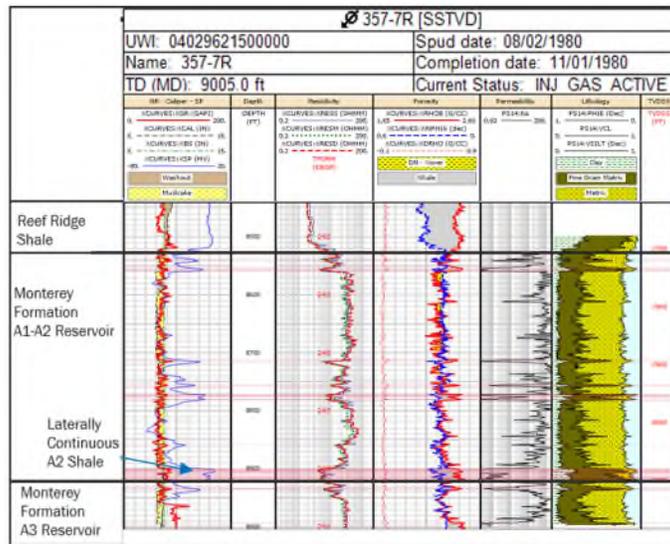
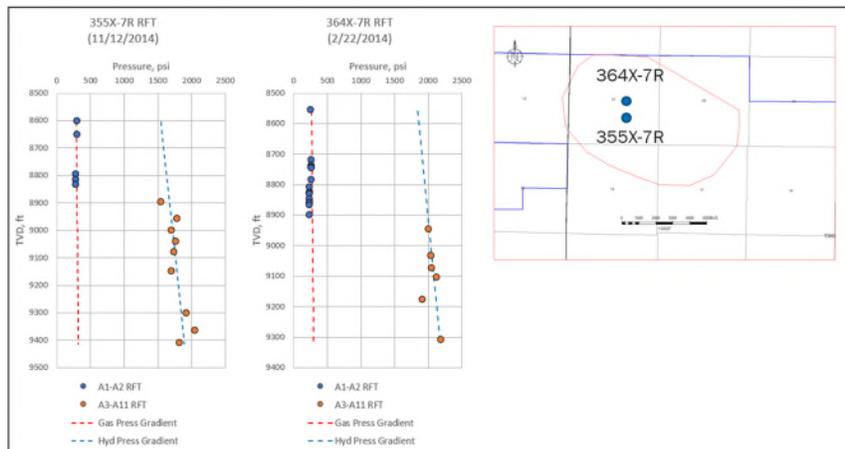


Figure 10: Repeat formation pressure data readings showing hydraulic separation between the A1-A2 and A3-A11 reservoirs. Large pressure difference between the two reservoirs and different fluid gradients as indicated by the red and blue dotted lines



CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for CO₂ migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for CO₂ miscible enhanced oil recovery.

Summary:

The Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as confinement by the Reef Ridge Shale.

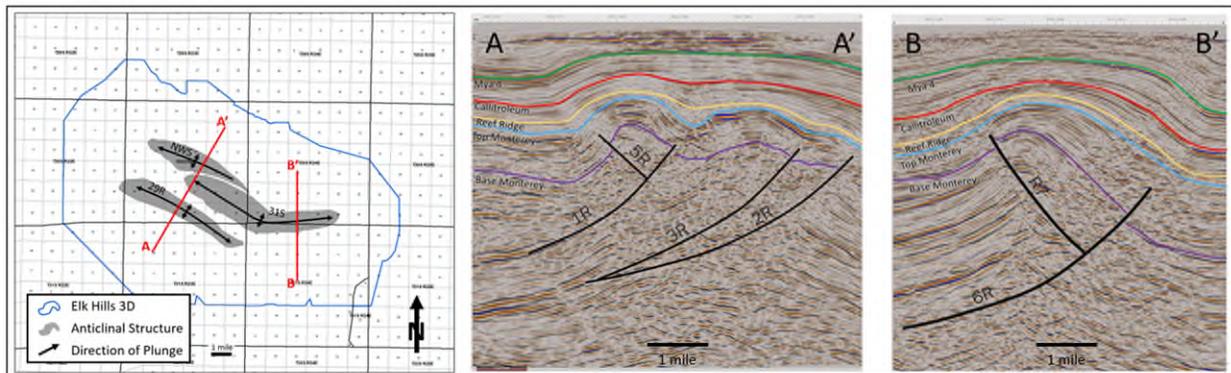
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 11 displays the location and extent of faults that helped to form the EHOV anticlines. Offsetting the NWS anticlines are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

Figure 11: EHOV Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOV anticlines with reverse faults.



Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO₂ injectate in the Monterey Formation A1-A2 sands:

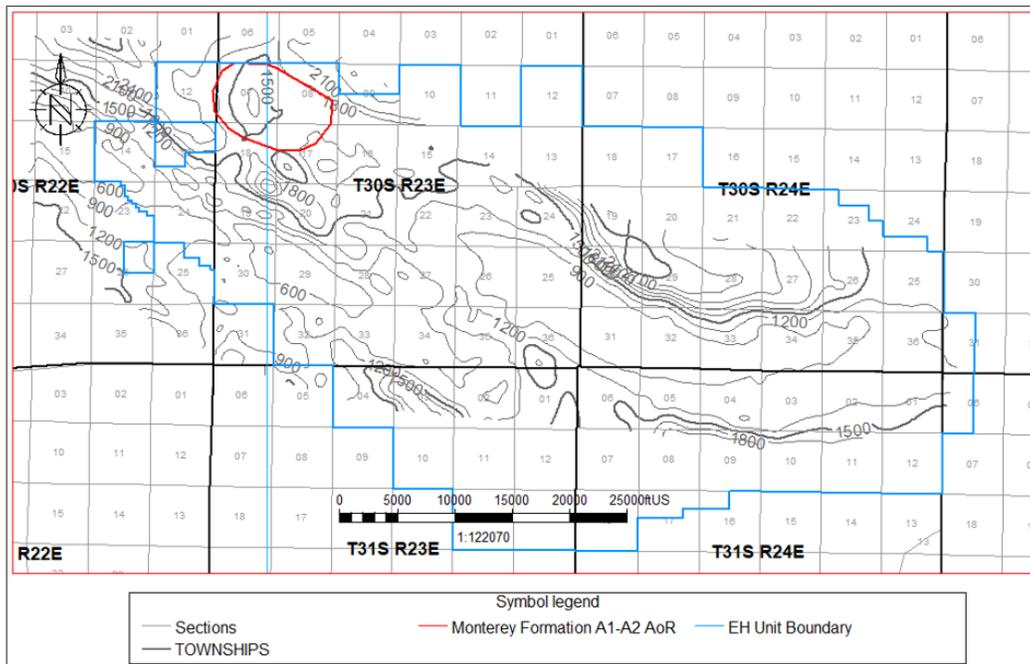
1. There are no faults that extend into the confining Reef Ridge Shale.
2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. A pressure differential exists above and below the Reef Ridge confining interval, confirming lack of communication.

4. Geochemical analysis of reservoirs within the EHOV also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO₂ injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOV the thickness averages 1,100 feet (Figure 12) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 12: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

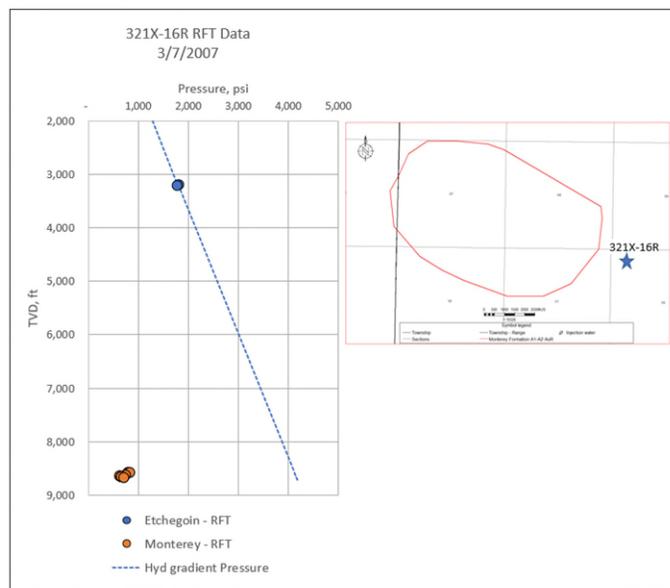
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than five million barrels of water and 175 billion cubic feet of gas have been injected into the Monterey Formation A1-A2 sands. There has been no evidence of water or gas migrating out of the reservoir or through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically and

confined.

3. Pressure Differentials

The Monterey Formation A1-A2 sequestration zone average current pressure is approximately 230 PSI. Overlying the sequestration zone, and separated by the confining Reef Ridge Shale, the Etchegoin Formation aquifer sands are at a much higher pressure of 1,500 PSI (0.43 PSI/foot gradient at 3,600 feet depth). This pressure differential of 1,300 PSI between the overlying Etchegoin Formation and Monterey Formation is maintained because the Reef Ridge is sealing and there are no transmissive features. Figure 13 shows an example of RFT pressure data collected in 2004 during the drilling of an Oil & Gas well near the project area. The RFT data shows that the Etchegoin is hydraulically separated from the deeper Monterey formation and at a much higher pressure.

Figure 13: Etchegoin and Monterey RFT data collected during the drilling of Oil & Gas well 321X-16R near the project area showing hydraulic separation between the two formations

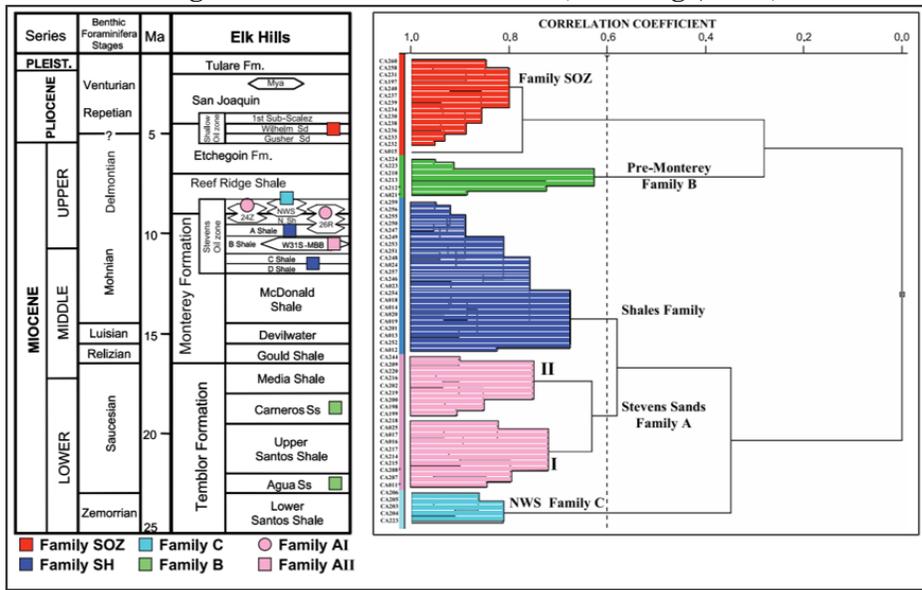


4. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 14) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals (sample locations shown on Figure 2). The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests “minimal up-section, [and] cross stratigraphic migration”. The authors conclude that the hydrocarbons present in the overlying formations are from “another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs” and not the result of upward movement from the older Miocene reservoirs.

The geochemical oil family data conclusions are supported by the pressure data (Figure 13) showing that formations are not in communication due to reservoir depletion.

Figure 14: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

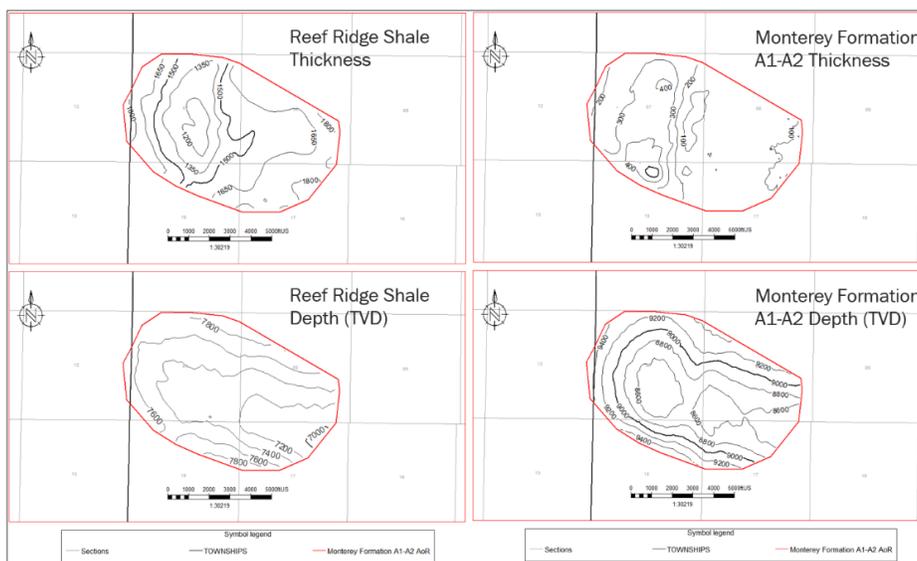
Depths and thickness of the Monterey Formation A1-A2 reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 15) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability due to deposition of the Monterey Formation sands. In the AoR, the Reef Ridge Shale minimum thickness corresponds to a high in Monterey Formation A1-A2 sand thickness.
3. Monterey Formation A1-A2 thickness variability is from pinch-out of the reservoir on the structure.

Table 1: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	1,122	1,892	1,555
	Depth (feet TVD)	6,929	7,962	7,441
Reservoir Monterey Formation A1-A2 Sand	Thickness (feet)	27	548	204
	Depth (feet TVD)	8,403	9,598	8,907

Figure 15: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth maps.



Variability in the thickness and depth of the either the Reef Ridge Shale or the Monterey Formation A1-A2 sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

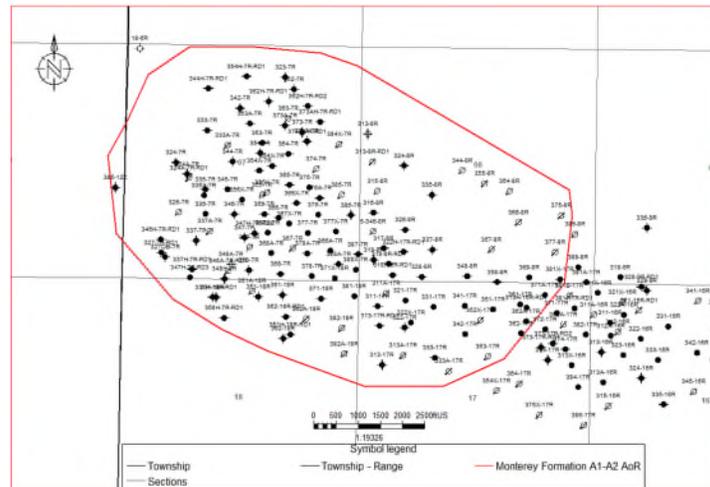
Facies Changes in the Injection or Confining Zone

The Monterey Formation A1-A2 reservoir and Reef Ridge Shale has been defined with extensive data (Figure 16), with a total of 255 well and spacing of 400-800 feet. Each of these wells is used to define stratigraphy, lithology/facies and reservoir properties for the static geological model and the maps shown in Figure 15. This quantity and spacing of data is more than sufficient to generate a data driven static model that define facies changes in for the reservoir and confining zone.

For example, during the drilling of well 355-7R in 1972 spontaneous potential (SP) resistivity (dual induction laterlog), density, neutron porosity and formation dip from 10,509' to 3,393', covering the Etchegoin dissipation zone, Reef Ridge Shale confining layer and the Monterey Formation A1-A2 storage reservoir. In addition 28 sidewall core samples were obtained over the same interval (no detailed analysis of the core samples). The log data supports the characterization of the injection zone and the confining zone at the well site.

Based on Monterey Formation A1-A2 operational experience and plume modeling results, there are no facies changes that will either impact injection operations or confinement.

Figure 16: Well data used to define the Monterey Formation A1-A2 injection reservoir and confining zone. These wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) that are used in the static geological model.



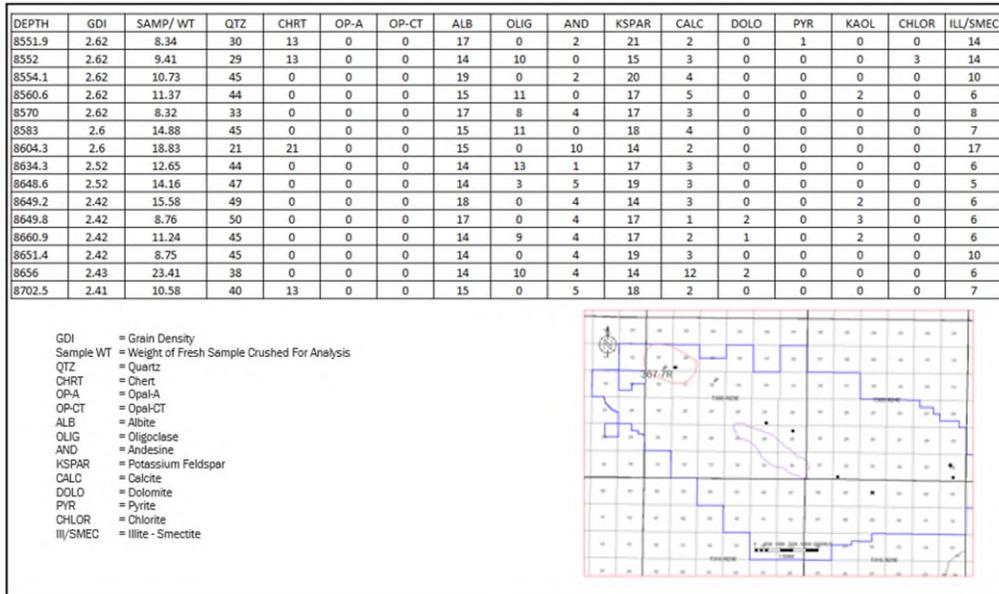
Mineralogy

Monterey Formation A1-A2:

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Offset well 367-7R

(Figure 17) provides an example of the mineralogy for the reservoir interval in 357-7R. Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Figure 17: Monterey Formation A1-A2 sand mineralogy from well 367-7R. The map shows the location for 367R and the other wells with XRD in the Elk Hills field.

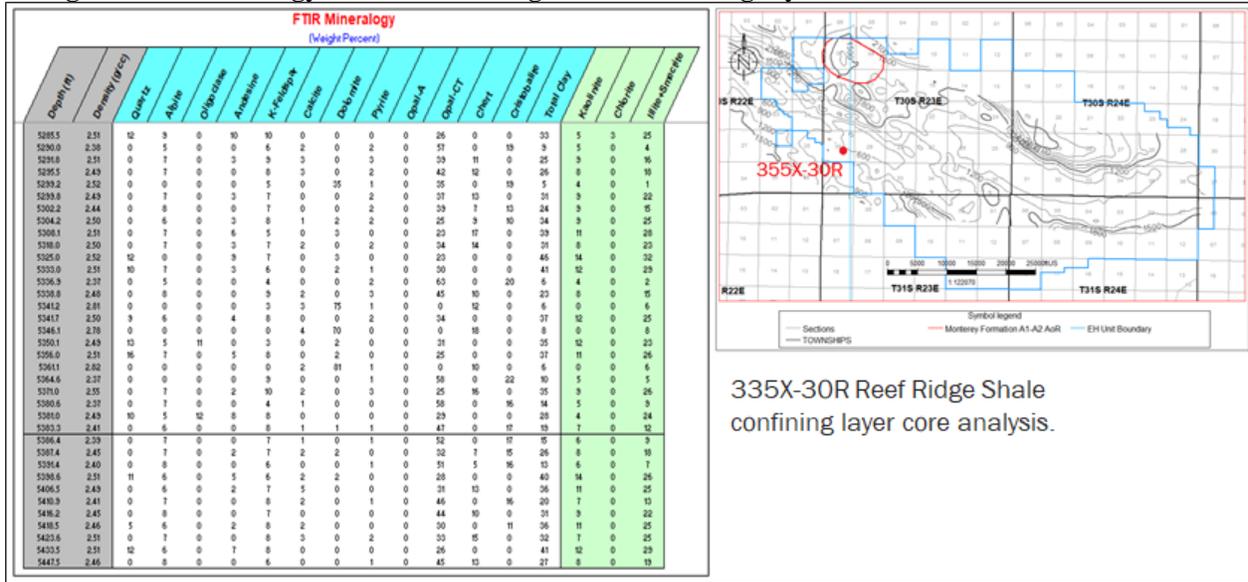


Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 18). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AOR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 18: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.



Porosity and Permeability

Monterey Formation A1-A2:

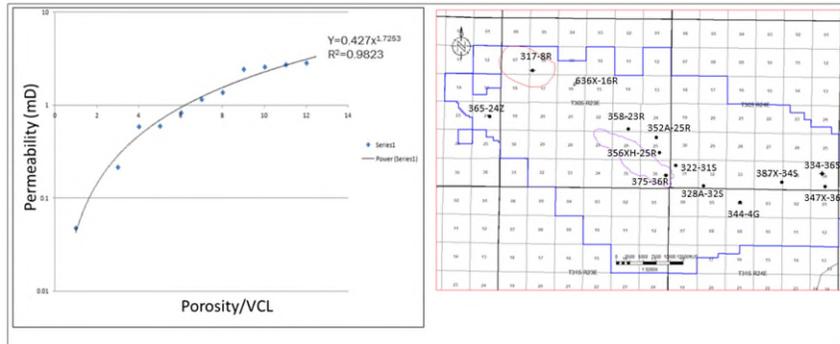
Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.

Volume of clay is determined by neutron-density separation and is calibrated to core data.

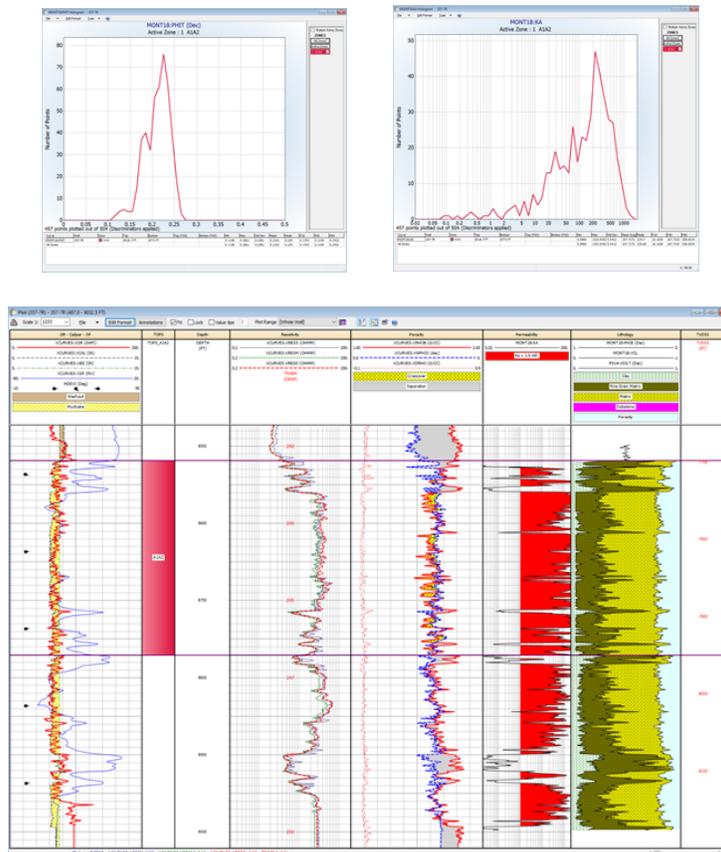
Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells (Figure 19) with 175 data points were used to calibrate log porosity and to develop a permeability transform. This distribution of wells and data points covers Monterey Formation sands in the Elk Hills field and ensures coverage of the porosity-permeability range in the storage reservoir. An example of the transform from core data is illustrated in Figure 19 below.

Figure 19: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume. Map shows the locations for wells with Monterey Formation sand core data used in the function.



In the example below for the Monterey Formation A1-A2 sands, the porosity ranges from 11% - 27% with a mean of 21%. The permeability ranges from 0.1 mD - 1300 mD with a log mean of 108 mD (Figure 20).

Figure 19: Porosity and permeability for well 377H-26R, showing the distribution and the input and output log curves. Lithology and clay volume (VCL) was calculated using the neutron-density log separation and gamma ray. Sands have less neutron-density separation compared to silts and shale.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2). For each of the project wells, Table 3 shows the average porosity and permeability of the Reef Ridge Shale. Using log data for the Reef Ridge in the project area, the mean log derived porosity is 15% and the log mean of the log derived permeability is 0.009md, which corroborates that the Reef Ridge is a low permeability cap rock.

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006
TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

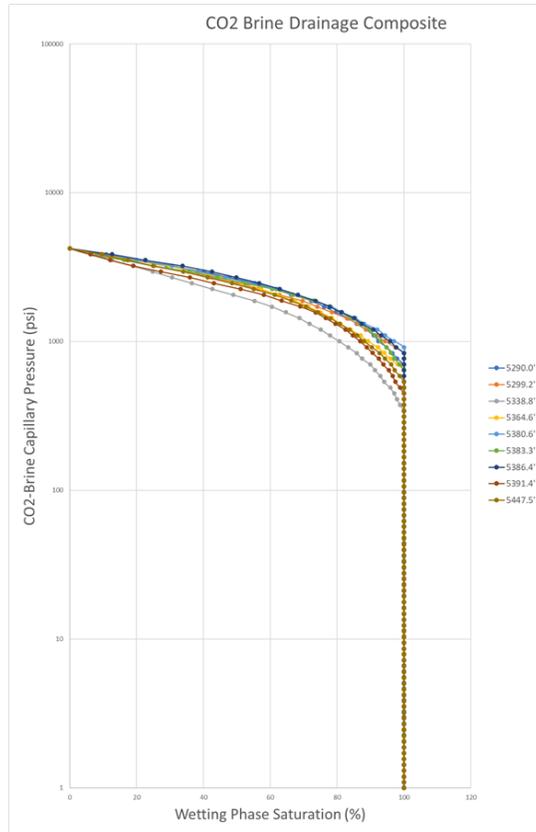
Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO₂-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 21). The capillary pressure was determined by applying CO₂-brine corrections to air-mercury test data. An interfacial

tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO₂-brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO₂-brine, respectively.

Figure 21: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 18 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 59,214 individual logging data points. The location for the 18 wells is shown on the map in Figure 22.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

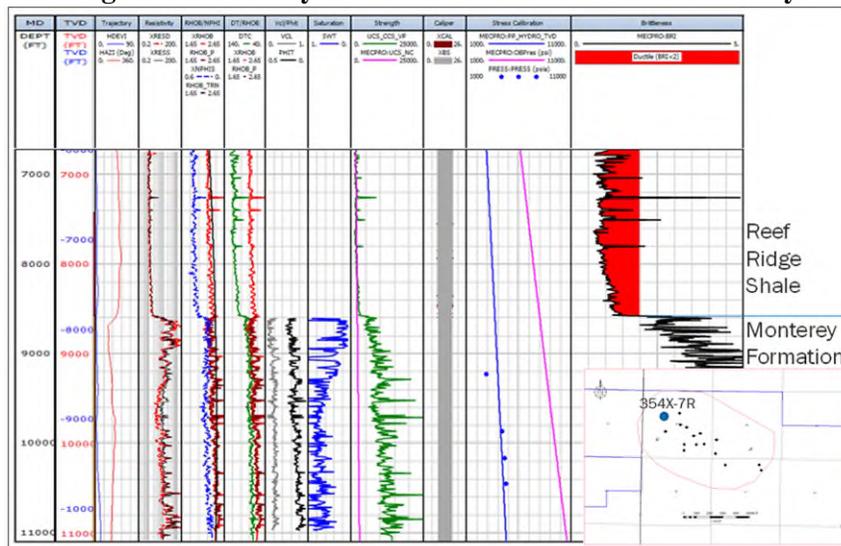
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_p$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 354X-7R is shown below (Figure 22). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method. Ductility less than two is shaded red.

Figure 22: Unconfined compressive strength and ductility calculations for well 354X-7R. The Reef Ridge Shale ductility is less than two and will be sufficiently.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure.

The average ductility of the confining zone based on the mean value from 18 wells is 1.24.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,452 psi.

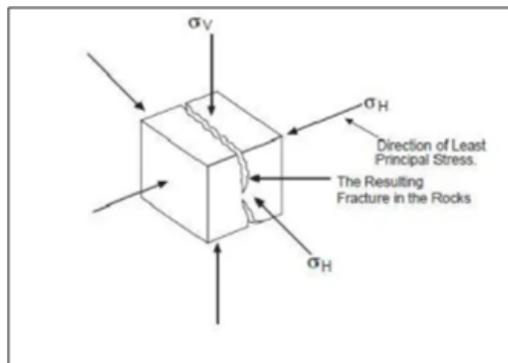
As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the Monterey Formation A1-A2 reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

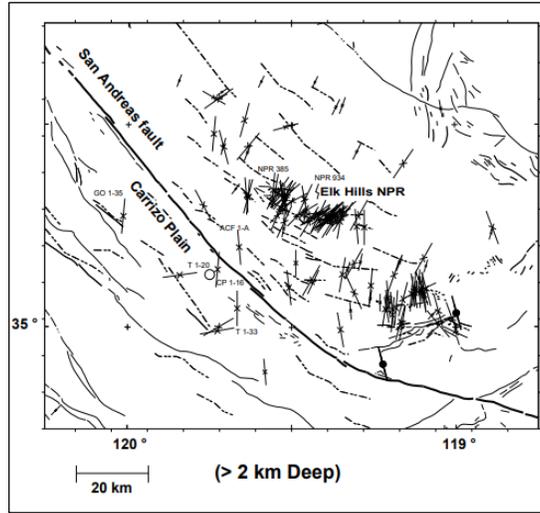
The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. In this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (Figure 23).

Figure 23: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.



Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 24 shows that the maximum principal stress (S_{Hmax}) in the Elk Hills area is largely oriented northeast – southwest.

Figure 24: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).



From a fracture test in well 327-7R-RD1, the Monterey Formation A1-A2 has a fracture gradient of 0.82psi/ft, based on the initial shut-in pressure with an overburden gradient of 0.94psi/ft and pore pressure gradient of 0.2psi/ft. Using this gradient, the injectors are planned to be operated such that they will not exceed 90% of the fracture pressure, which equates to a maximum allowable bottomhole gradient of $0.9 \times 0.82 \text{ psi/ft} = 0.738 \text{ psi/ft}$. Applying this gradient to the two injector locations, the maximum bottom injection pressures are shown in table 3.

Table 3: Injectors 355-7R and 357-7R maximum allowable bottom hole injection pressure (psi) for the Monterey Formation A1-A2 injection zone.

Stress	357-7R	355-7R
Reservoir Fracture Gradient with Safety Factor (psi/foot)	0.738	0.738
Monterey Formation A1-A2 Injection Zone Top (feet TVD)	8,485	8,462
Fracture Pressure (psi)	6261.9	62,44.9

In the project AoR there is no site specific Reef Ridge Shale fracture pressure or fracture gradient. A Reef Ridge Shale step rate test will be conducted as per the preoperational testing plan. In the interim, CTV is making the assumption that the Reef Ridge Shale will have a similar fracture gradient as the Monterey Formation.

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO₂ injection. A modified Barton-Bandis model can be used to allow CO₂ to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO₂ is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO₂ to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 4. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI. These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 4: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	FAILURE PRESSURE, PSI
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

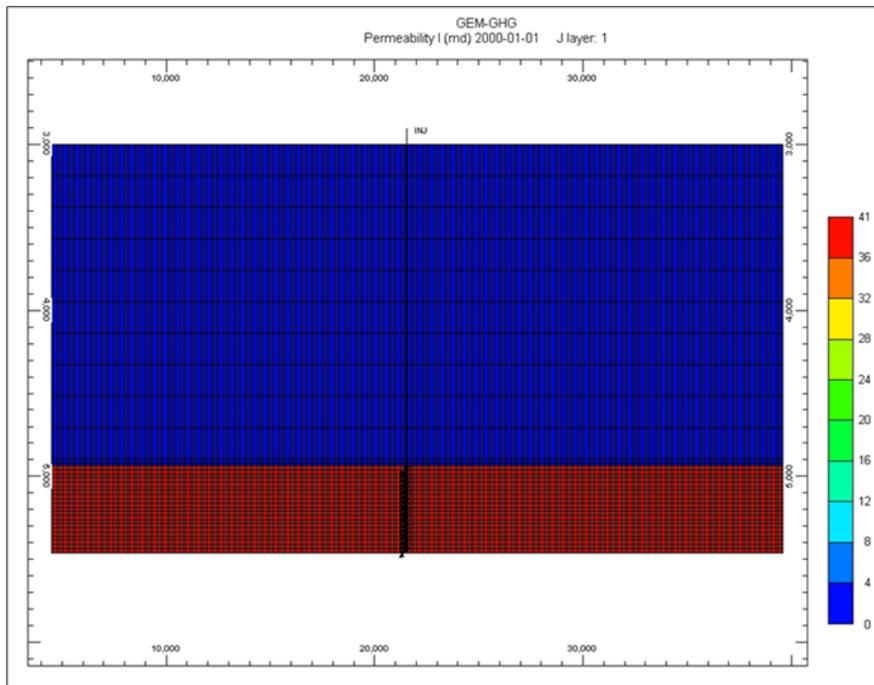
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 25.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO₂ with a maximum injection pressure of 10,000 PSI.

Figure 25: Geomechanics Model.

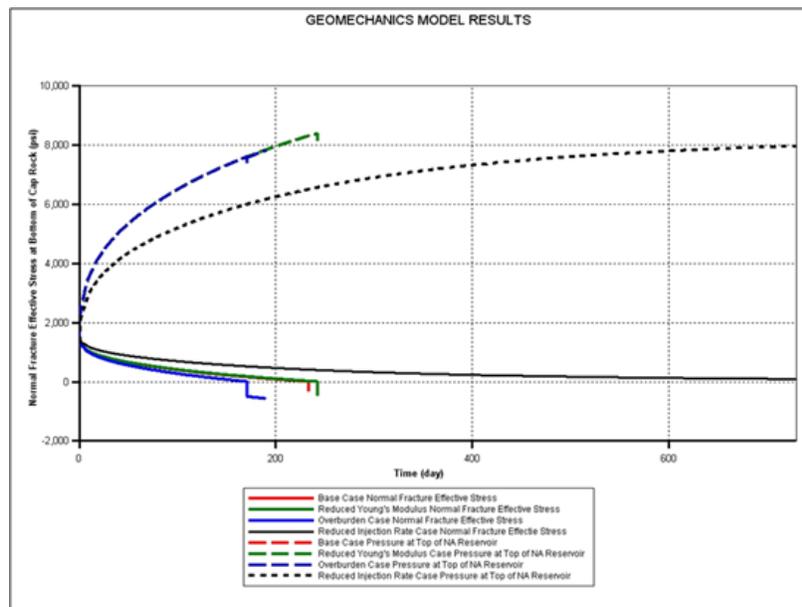


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 26 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO₂ bleeding into the cap rock despite the very low vertical permeability.

Figure 26: Normal Fracture Stress and Pressure for Geomechanics Cases. Base case follows the reduced Young's Modulus case.



Geomechanical Modeling Parameters

The geomechanical parameters used in the modeling were selected to represent a range of values for thickness, poisons ratio and Youngs Modulus. The following is a short description for parameter variability selection:

Thickness: Reef Ridge thickness scenarios for the geomechanical modeling was 795 feet and 1,935 feet. The mean thickness of the Reef Ridge Shale confining layer overlying the Monterey Formation A1-A2 AoR is 1,555 feet thick (Figure 12) as derived from open-hole log interpretation, which is between the parameters modeled.

Poisson's Ratio: Compressional and shear sonic logs were used to calculate Poisson's Ratio (Yale, 2017).

$$v_{dyn} = v_{stat} = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)}$$

The following table shows the range of values determined for Poisons Ratio and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (1140' of Caprock)	P10	P50	P90
Caprock Reef Ridge	0.23	0.23	0.23	0.24	0.28	0.32
Reservoir A1-A2	0.25			0.19	0.25	0.3

Young's Modulus: Young's Modulus was calculated using compressional and shear sonic and bulk density logs. The dynamic to static correction applied was the Lacy shale method (Lacy, 1997):

$$E_{dyn} = \frac{\rho V_s^2 (3V_p^2 - 4V_s^2)}{(V_p^2 - V_s^2)}$$

- See equation 8.1 in Fjaer et. al, 2008

$$E_{stat} = 0.0428E_{dyn}^2 + 0.2334E_{dyn}$$

- See equation 2 in Lacy, 1997.

The following table shows the range of values determined for Young's Modulus and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case (Top 1140' of Caprock)	P10 E	P50 E	P90 E
Caprock Reef Ridge	0.9	0.8	0.6	0.66	0.91	1.36
Reservoir A1-A2	0.725			0.79	0.85	0.92

Seismic History [40 CFR 146.82(a)(3)(v)]

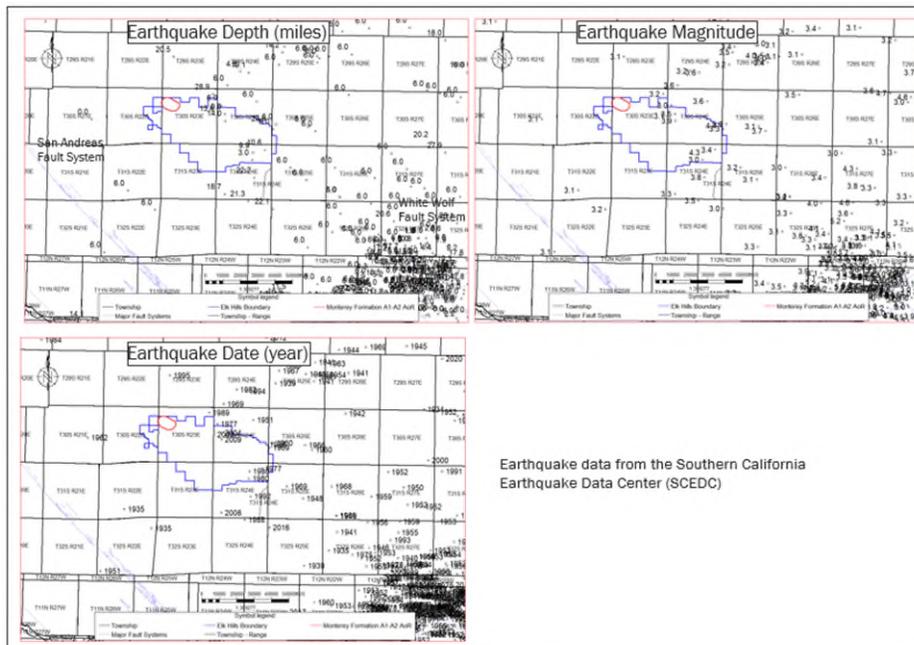
Seismic History:

The EHOFF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOFF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

There have been no earthquakes in the AoR (Figure 27). In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOFF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 27: Earthquakes in the southern San Joaquin Basin with a magnitude greater than 3 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.



Seismic Risk:

The EHOFF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOFF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

The following is a summary of CTVs seismic risk:

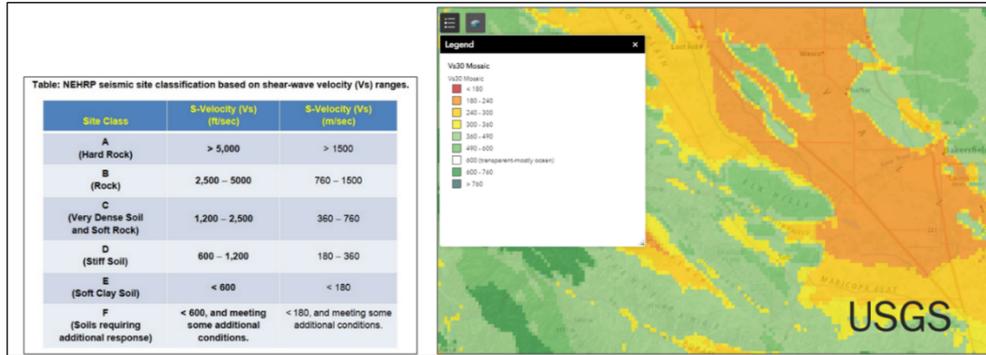
Has a geologic system free of known active faults and fractures and capable of receiving and containing the volumes of CO₂ proposed to be injected.

- Extensive historical operations in the Monterey Formation A1-A2 reservoir is valuable experience to understand operating conditions such as injection volumes and reservoir containment. The strategy to limit the injected CO₂ to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
- VS₃₀, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOFF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high Vs₃₀ means (Figure 28) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
- There are no faults or fractures identified in the AoR that will impact the confinement of CO₂ injectate.

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;

- The strategy to limit the injected CO₂ to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.

Figure 28: VS30 analysis from the USGS that supports the EHO has a low risk for shallow well and infrastructure impact due to earthquakes.



Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur.
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations.

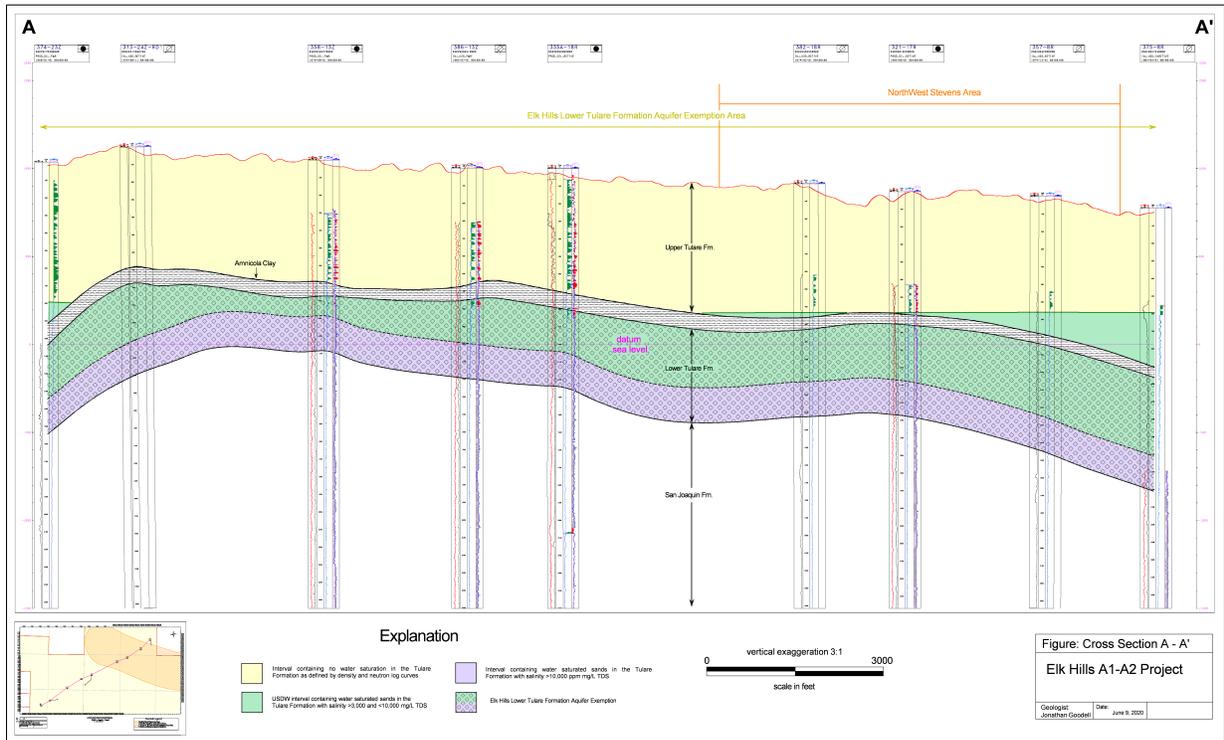
Poses a low risk of inducing a felt seismic event.

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining layer.
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.
- The operational strategy of keeping the reservoir pressure at or beneath the initial pressure of the reservoir has been designed to reduce the risk for seismic events.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

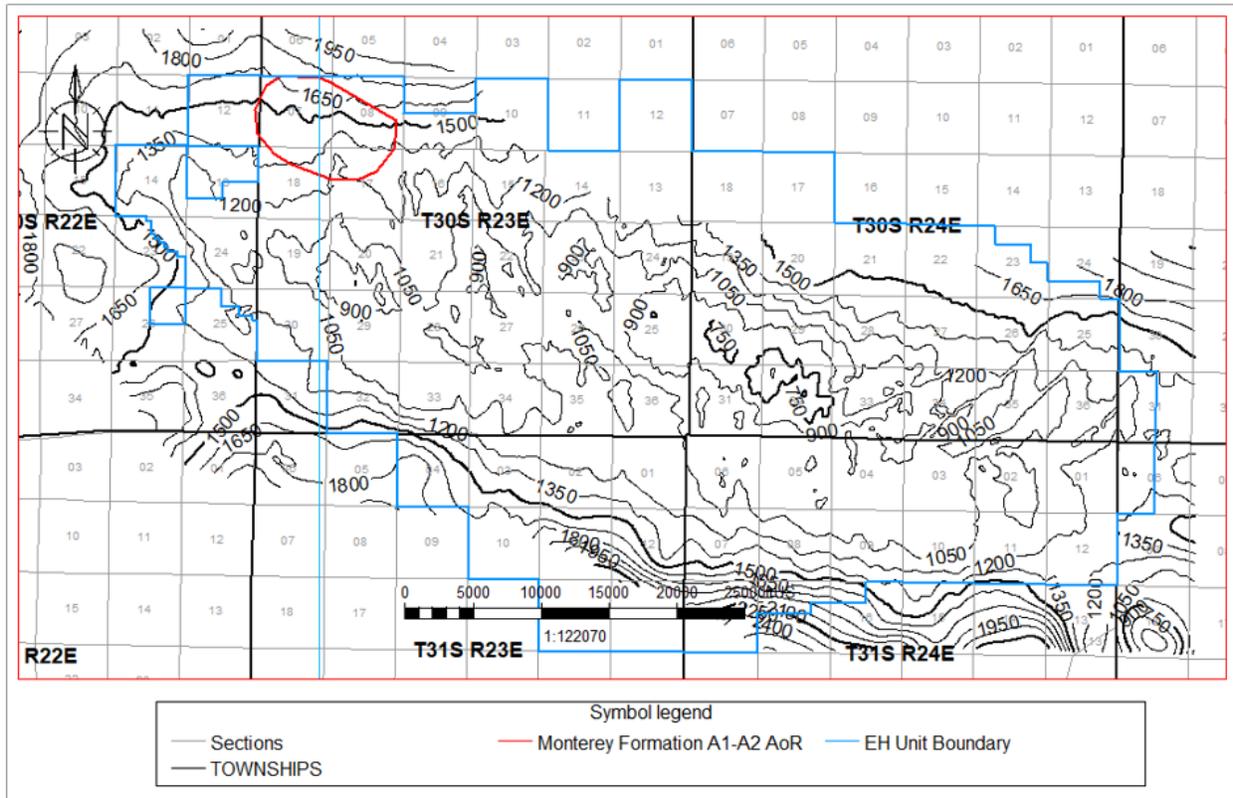
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 29). CTV has studied the shallow aquifers at the EHOV extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 29: Cross-section showing the Tulare Formation USDW. The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands have 3,000 – 10,000 TDS water at the base, on the edges of the Northwest Stevens anticline.



The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 29). The depth is 600 - 2,500 feet and the thickness ranges from 1,200 - 1,500 feet (Figure 30).

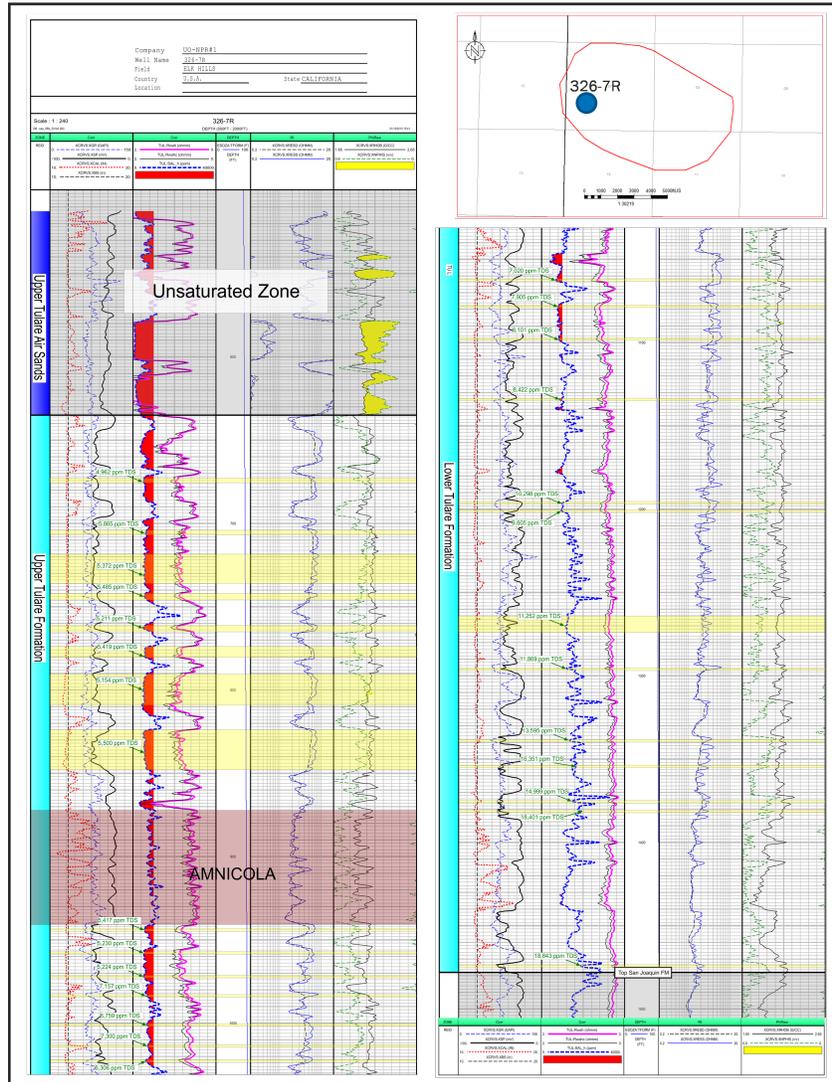
Figure 30: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare USDW. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 31). The characteristic density-neutron crossover (orange-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 31 shows the Upper Tulare USDW overlain by the Upper Tulare air sands. The Upper Tulare is 850 feet in depth and is separated from the underlying Reef Ridge Shale confining layer by 6,450 feet and the Monterey Formation A1-A2 sequestration reservoir by 7,650 feet.

Figure 31: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, Upper Tulare USDW and Lower Tulare exempt aquifer.



Salinity Calculation

Calculation of salinity as shown in Figure 31 is a four step process:

- (1) converting measured density to formation porosity

The equation to convert measured density to porosity is:

$$POR = (R_{\text{hom}} - R_{\text{HOB}}) / (R_{\text{hom}} - R_{\text{hof}})$$

Parameter definitions for the equation are:

POR is formation porosity

R_{hom} is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

R_{HOB} is calibrated bulk density taken from well log measurements (g/cc)

R_{hof} is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

- (2) calculation of apparent water resistivity using the Humble equation,
 The Humble equation calculates apparent water resistivity. The equation is:

$$Rwah = ((POR**m) * XRES D)/a$$
 Parameter definitions for the equation are:
 Rwah is apparent water resistivity (ohmm)
 POR is formation porosity as derived from the density conversion formula
 m is the cementation factor; 2.15 is the standard value
 XRES D is deep reading resistivity taken from well log measurements (ohmm)
 a is the archie constant; 0.62 is the standard value
- (3) correcting apparent water resistivity to a standard temperature
 Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

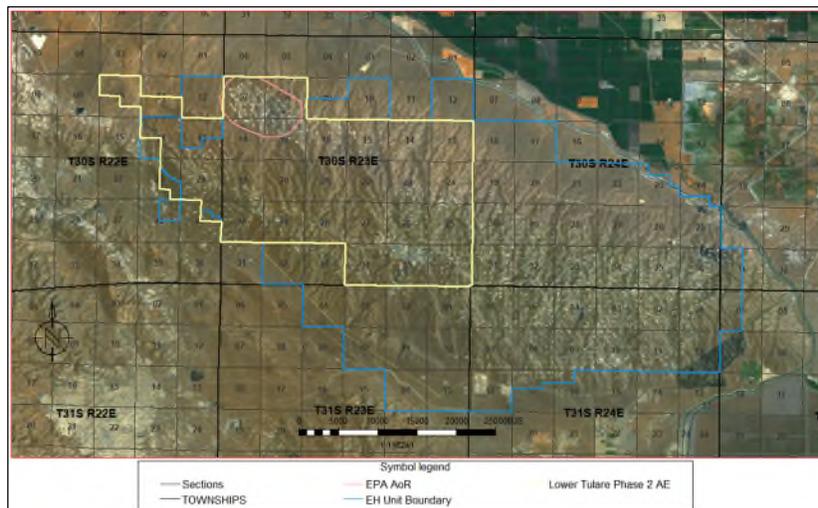
$$Rwahc = Rwah * ((TEMP)+6.77)/(75+6.77)$$
 Parameter definitions for the equation are:
 Rwahc is apparent water resistivity (ohmm), corrected to surface temperature
 TEMP is down hole temperature based on temperature gradient (DegF)
- (4) converting temperature corrected apparent water resistivity to salinity.
 The following formular was used:

$$SAL_h = 10 ** ((3.562-(Log10(Rwahc-0.0123)))/.955)$$
 Parameter definitions for the equation are:
 SAL_h is salinity from corrected Rwahc (ppm)
 Rwahc is apparent water resistivity, corrected to surface temperature (ohmm),

Water Samples

Tulare Formation water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum containment levels (MCL).

Figure 32: Lower Tulare aquifer exemption boundary.



In 2018 the Lower Tulare aquifer (boundary shown on map in Figure 32) was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

The Upper Tulare USDW has 3,000-10,000 mg/l TDS on the edges of the NWS anticline. Water quality for the Upper Tulare USDW is shown in Figure 33. The water is not used within the AoR or the EHO.

Figure 33: Upper Tulare USDW and Lower Tulare Formation water analysis.

Upper Tulare					Lower Tulare																																																																																																																																																																																																																																																																																																		
<p>Table 6a. WATER SOURCE WELL #43WS-133 WATER ANALYSIS DATA (mg/l/g)</p> <table border="1"> <thead> <tr> <th>DATE</th> <th>6-95</th> <th>7-95</th> <th>8-95</th> <th>9-95</th> </tr> </thead> <tbody> <tr> <td>SAMPLE #</td> <td>95094</td> <td>95150</td> <td>95182</td> <td>95189</td> </tr> <tr> <td>CONSTITUENTS:</td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>Calcium, Ca</td> <td>230</td> <td>230</td> <td>220</td> <td>220</td> </tr> <tr> <td>Magnesium, Mg</td> <td>85</td> <td>85</td> <td>92</td> <td>93</td> </tr> <tr> <td>Sodium, Na</td> <td>1280</td> <td>1300</td> <td>1200</td> <td>1300</td> </tr> <tr> <td>Potassium, K</td> <td>3.2</td> <td>3.8</td> <td>3.8</td> <td>8.6</td> </tr> <tr> <td>Iron, Fe</td> <td>0.4</td> <td>0.51</td> <td>0.38</td> <td>0.54</td> </tr> <tr> <td>Hydroxide, OH</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>Carbonate, CO3</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>Bicarb, HCO3</td> <td>180</td> <td>190</td> <td>190</td> <td>180</td> </tr> <tr> <td>Chloride, Cl</td> <td>1360</td> <td>1400</td> <td>1300</td> <td>1400</td> </tr> <tr> <td>Sulfate, SO4</td> <td>1600</td> <td>1600</td> <td>1500</td> <td>1600</td> </tr> <tr> <td>Sulfide, S</td> <td><5.0</td> <td><5.0</td> <td><5.0</td> <td><5.0</td> </tr> <tr> <td>Totals</td> <td>4660</td> <td>4700</td> <td>4400</td> <td>4700</td> </tr> <tr> <td>Boron, B</td> <td>4.7</td> <td>4.6</td> <td>4.7</td> <td>4.7</td> </tr> <tr> <td>TDS (Grav)</td> <td>4890</td> <td>4800</td> <td>4900</td> <td>4900</td> </tr> <tr> <td>Hardness, CaCO3</td> <td>920</td> <td>920</td> <td>930</td> <td>930</td> </tr> <tr> <td>Alkalinity, CaCO3</td> <td>150</td> <td>160</td> <td>160</td> <td>150</td> </tr> <tr> <td>Sodium Chloride</td> <td>3690</td> <td>3760</td> <td>3560</td> <td>3800</td> </tr> <tr> <td>pH</td> <td>7.8</td> <td>8.1</td> <td>8.0</td> <td>7.9</td> </tr> <tr> <td>Electrical Conductivity</td> <td>6.99</td> <td>7.02</td> <td>6.99</td> <td>6.99</td> </tr> <tr> <td>Specific 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Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

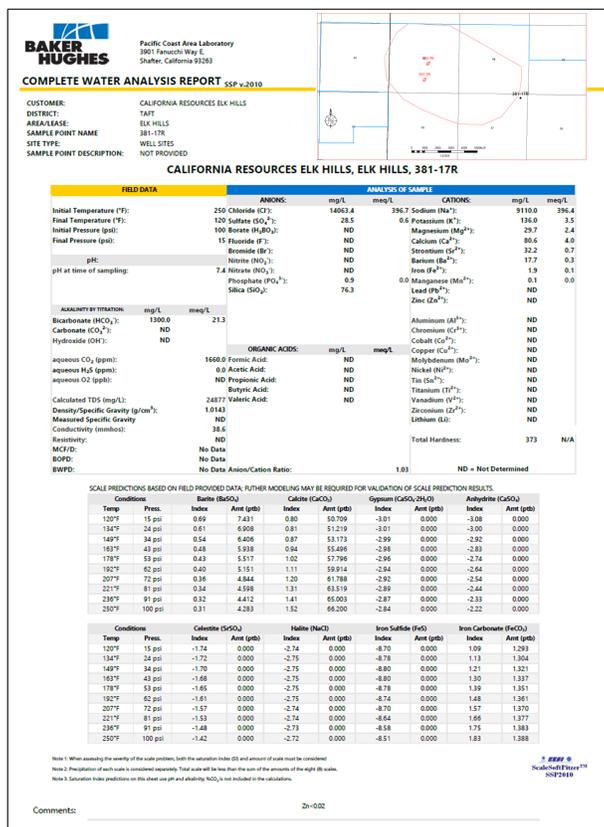
Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry A1-A2 Reservoir:

The Monterey Formation A1-A2 reservoir has a gas cap that overlies a thin oil band and a basal water zone. CRC and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation A1-A2 geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Figure 34 shows the water chemistry from well 381-17R, taken from a sand underlying the Monterey Formation A1-A2 reservoir. Reservoir depletion of the Monterey Formation A1-A2 has reduced the water saturation to residual, preventing representative water sampling.

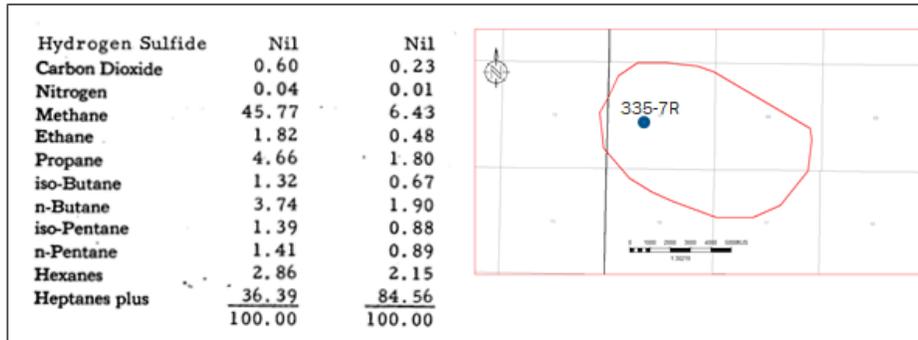
Figure 34: Monterey Formation A1-A2 reservoir water geochemistry from well 381-17R. Monterey Formation total dissolved solids based on well 381-17R is 24,877, well above USDW standards.



The hydrocarbon composition for the Monterey Formation A1-A2 reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 35 shows the results of the hydrocarbon composition for well 335-7R within the AoR. Oil composition analysis

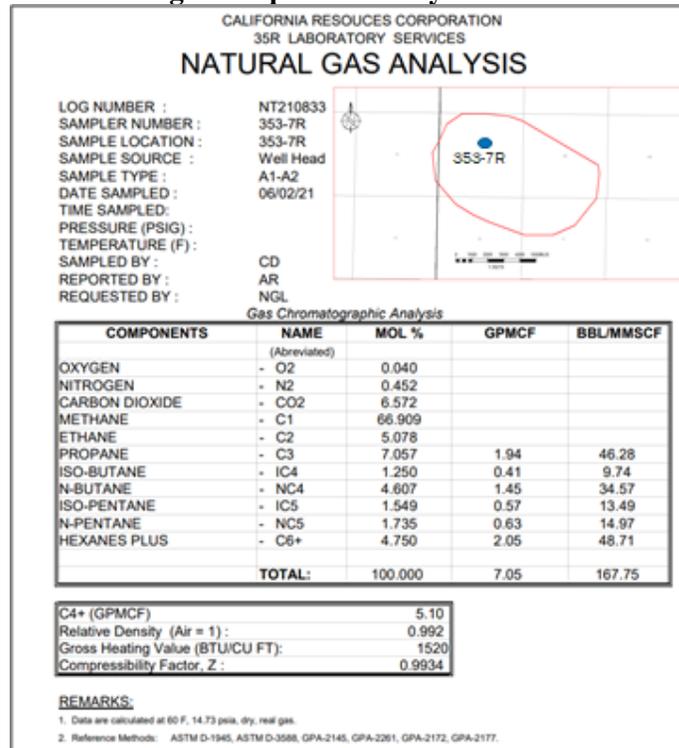
was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 35: Monterey Formation A1-A2 hydrocarbon geochemistry from well 335-7R in 1974.



Gas composition for the Monterey Formation A1-A2 is collected to assess the changing concentration of key components. Since 2011, CTV has used two injectors for reservoir pressure support; 357-7R and 355-7R to inject gas containing up to 44% CO₂. Figure 36 shows the produced natural gas analysis for 353-7R in 2021. Note that the composition has 6.5 mole % CO₂.

Figure 36: Natural gas composition analysis for well 353-7R in 2021.



Monterey Formation A1-A2 Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO₂ injectate:

1. The Monterey Formation A1-A2 reservoir has a low current water volume (~15% saturation in the gas cap and 85% in the thin oil leg) due to production related to oil and gas operations, where four million net barrels of water have been produced. This low volume of water will minimize both the quantity of CO₂ that will dissolve in solution and the quantity of carbonic acid formed in-situ.
2. Residual oil saturation (15%) in the Monterey Formation A1-A2 reservoir will also dissolve only a small amount of CO₂.
3. The Monterey Formation A1-A2 has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO₂ and carbonic acid and any dissolution or changes that occur will be on grain surfaces.
4. Since 2011 6.3 billion cubic feet of gas has been injected in the 357-7R and 355-7R wells, consisting of up to 44% CO₂. Injectivity of the reservoir has not changed.

The oil and water CO₂ trapping mechanisms have been incorporated in the computational modeling and will be discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

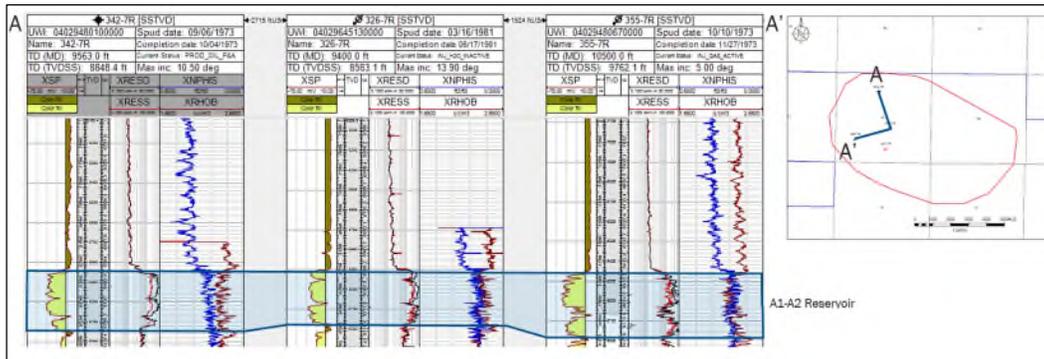
There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO₂ injectate.

Site Suitability [40 CFR 146.83]

The Monterey Formation A1-A2 reservoir in the Northwest Stevens anticline was discovered in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the Monterey Formation A1-A2 reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. Figure 37 shows the continuity of the A1-A2 reservoir and illustrates representative logs data collected during drilling used to develop the static model. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

Figure 37: Cross section showing continuity of the A1-A2 reservoir. Logs shown are representative of those collected during drilled and used to develop the static geological model.



A key component of the A1-A2 reservoir characterization was the development of a geo-cellular model, which is used to assess CO₂ plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale). Cross-sections in Figures 38 and 39 shows the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers supports predictable plume development.

CO₂ Injectate Confinement:

Confinement of CO₂ injected into the storage reservoir is supported by the following:

1. Prior to discovery of the Monterey Formation A1-A2 reservoir, a gas cap with underlying oil was confined for several million years.
2. The Reef Ridge Shale primary confining layer is 1,500 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage.

3. Cross section A-A' (Figure 38) shows the lateral confinement of the injected CO₂ plume by the anticline structure. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO₂ does not migrate beyond the edges of the anticline structure or into the Reef Ridge shale.
4. In Cross section B-B' (Figure 39) the up-dip CO₂ plume is confined by shale and the non-deposition of reservoir sands.

Figure 38: Plume modeling results showing lateral confinement of the CO₂ plume by the edges of the anticline structure 50 years post injection.

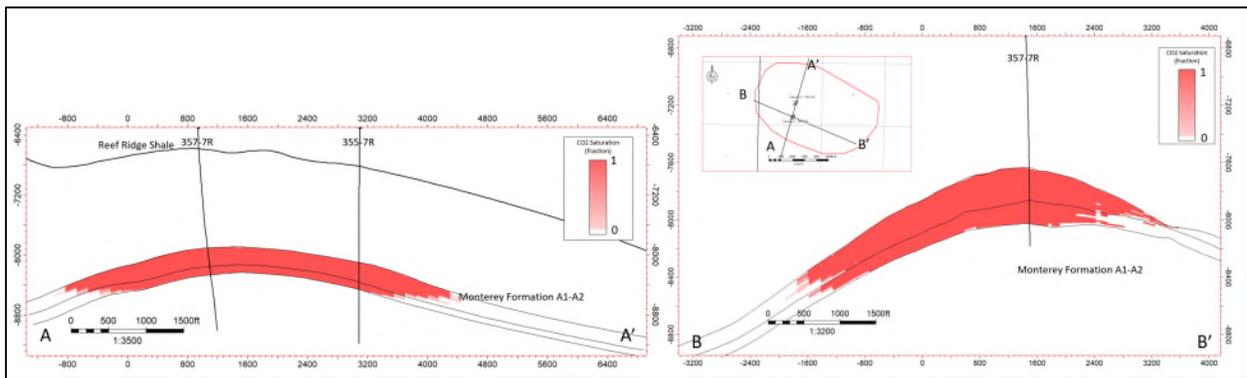
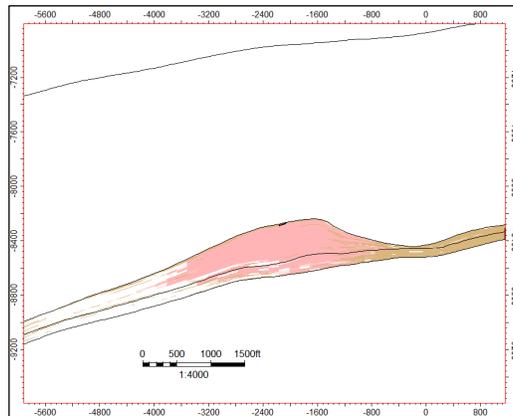


Figure 39: Plume modeling results showing the confinement of the plume against the up-dip pinch-out of the A1-A2 sand facies and the increasing shale facies.



Storage capacity for the Monterey Formation A1-A2 storage reservoir based on computational modeling results is approximately 8 -10 million tonnes of CO₂. This is sufficient capacity for the total proposed injectate.

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