ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Document Version History

Version	Submission Date	File Name	Description of Change
1	8/2/2021	Att B – AoR_CA Final	Original submission as part of Elk Hills A1-A2 Storage project
2	3/31/2022	Att B – AoR_CA Final V2	Updated submission to address EPA evaluation from 1/11/2022. Updated images and the following sections – Model domain, Fracture pressure and fracture gradient, Computational modeling results, Triggers for re-evaluation of AoR
3	11/4/2022	Att B – AoR_CA Final V3	Updated submission to address EPA evaluation from 7/20/2022. Following sections updated – Boundary Conditions, Initial Conditions, Operational Information, Fracture pressure and fracture gradient, Computational modeling results, Triggers for AoR reevaluation
4	3/19/2024	Att B – AoR_CA Final V4	Updated submission to address EPA questions from 6/16/2023

Facility Information

Facility name: Elk Hills A1-A2 Storage Project
357-7R & 355-7R

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Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Well completion, production, and injection data from the reservoir's entire depletion history

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CalCapture A1-A2 project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

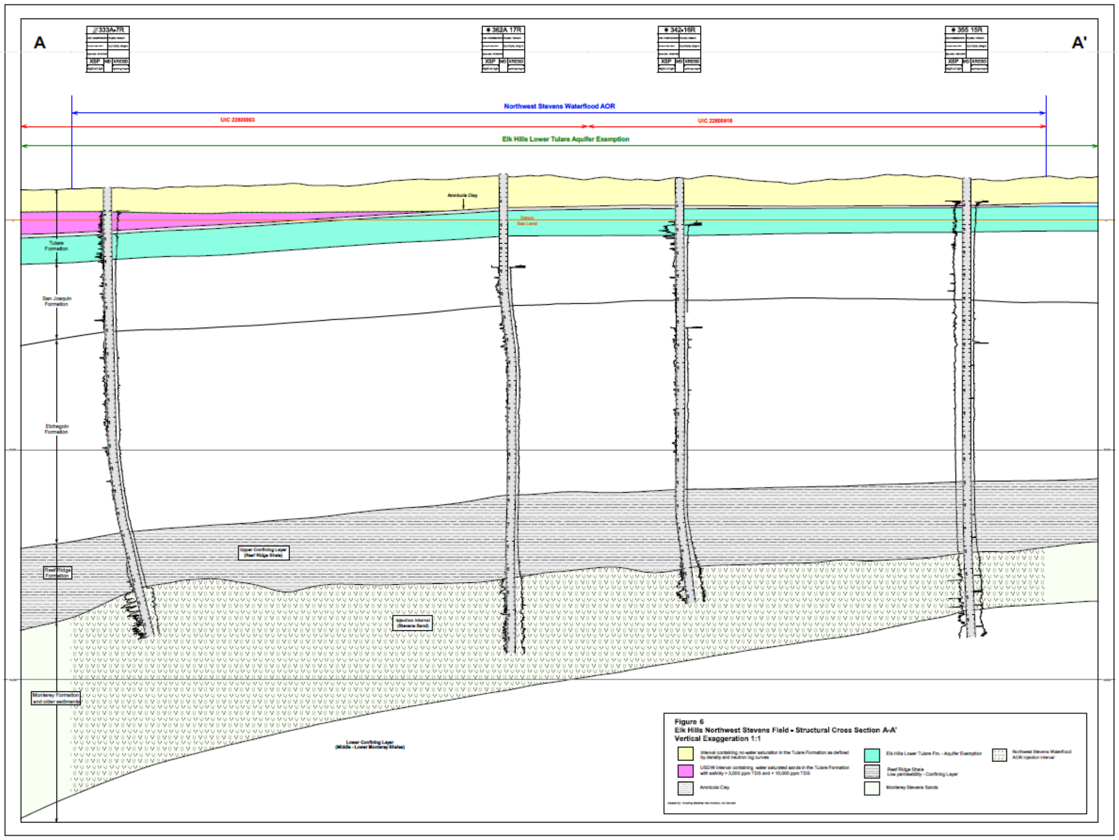
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands pinching-out on the NWS anticline.



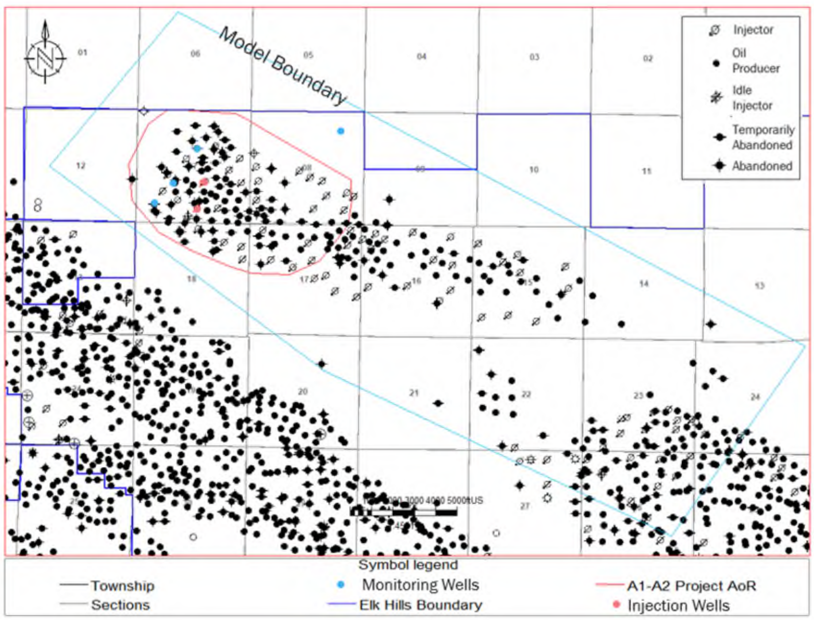
The Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970’s and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was “blown-down”, depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer. Recent and historical data showing this and maintenance of pressure differential between the A1-A2 reservoir, underlying A3-A11 reservoir and overlying Etchegoin formation are shown in Figure 13 and Figure 14.

Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.

Process	Phase	Volume
Production	Oil	28 million barrels
	Gas	193 billion cubic feet
	Water	9 million barrels
Injection	Water	6 million barrels
	Gas	175 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model used in computational modeling.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

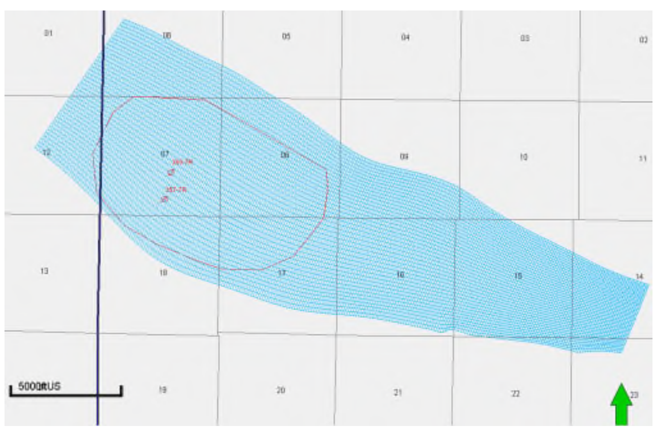
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6,095,241.81	**Coordinate of X max**	6,122,433.26
Coordinate of Y min	2,302,015.15	**Coordinate of Y max**	2,316,903.12
Elevation of bottom of domain	-10,426.35	**Elevation of bottom of domain**	-6,670.36

The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 3) at 150 feet x 150 feet. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement.

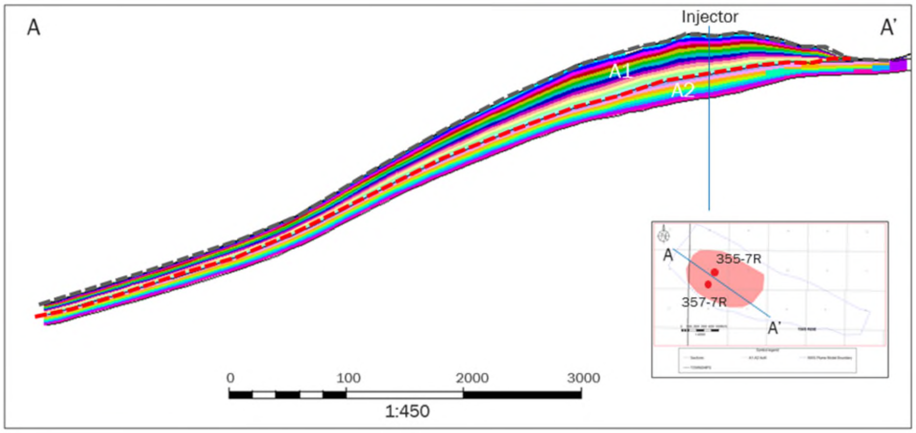
The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were defined to include the entire Northwest Stevens anticline, the plume extent and all Monterey Formation sands.

Figure 3: Plan view of the model boundary and project AoR.



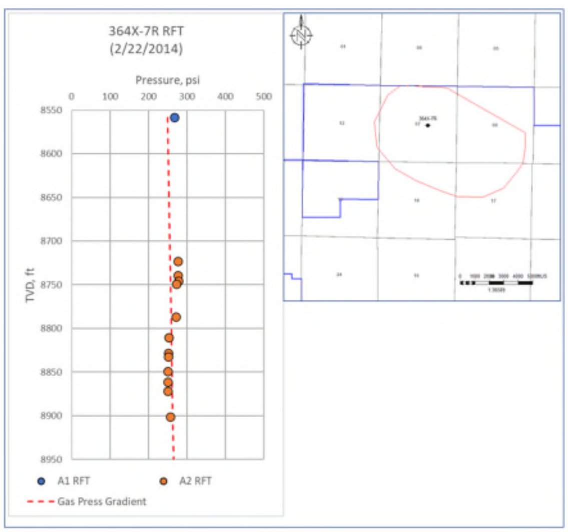
The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 proportional layers (Figure 4) respectively, resulting in an average grid cell height of 11.5 feet. The model grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 4: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.



The A1-A2 sands were modeled separately to ensure stationarity for the property distribution. The reservoirs are in communication as demonstrated by the pressures shown in Figure 5.

Figure 5: A1 and A2 reservoir pressure from well 364X-7R.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 6) that is dependent on porosity and clay volume.

Figure 6: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

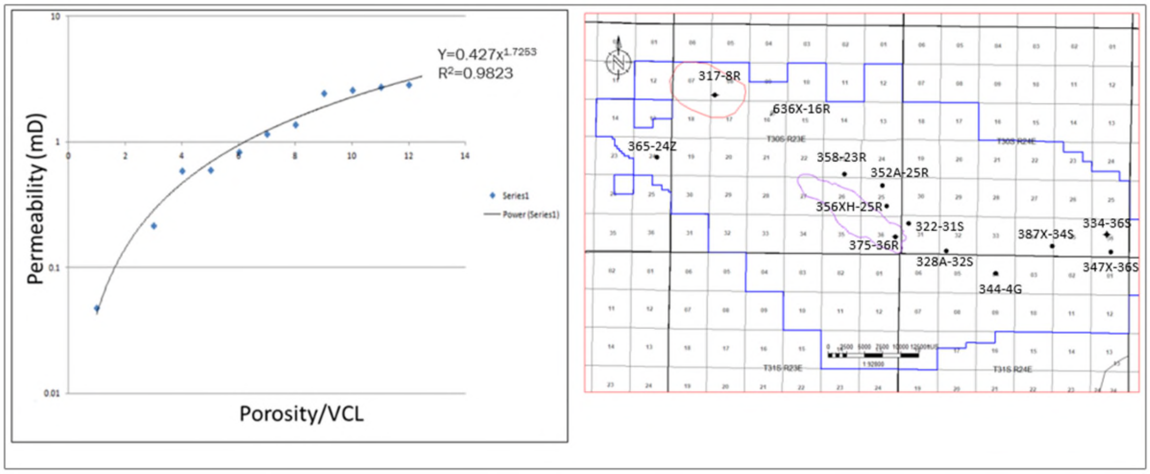


Figure 7: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.

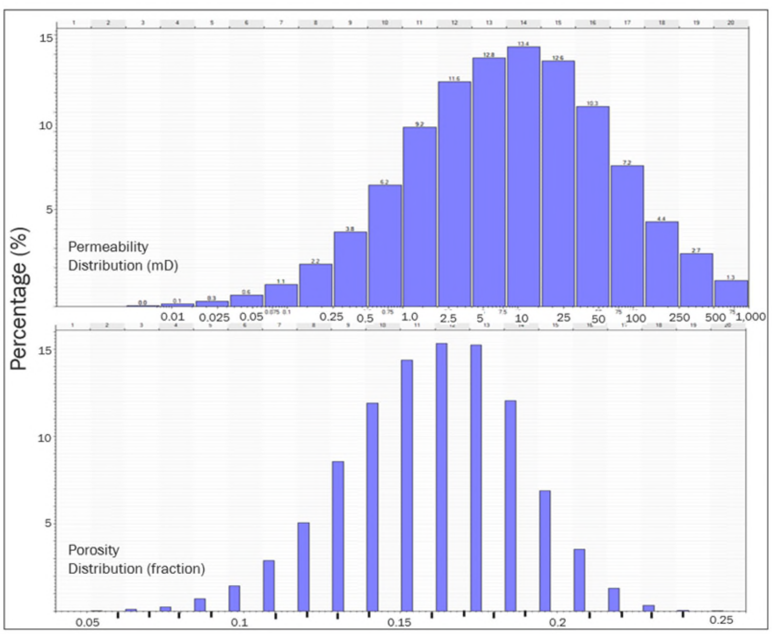
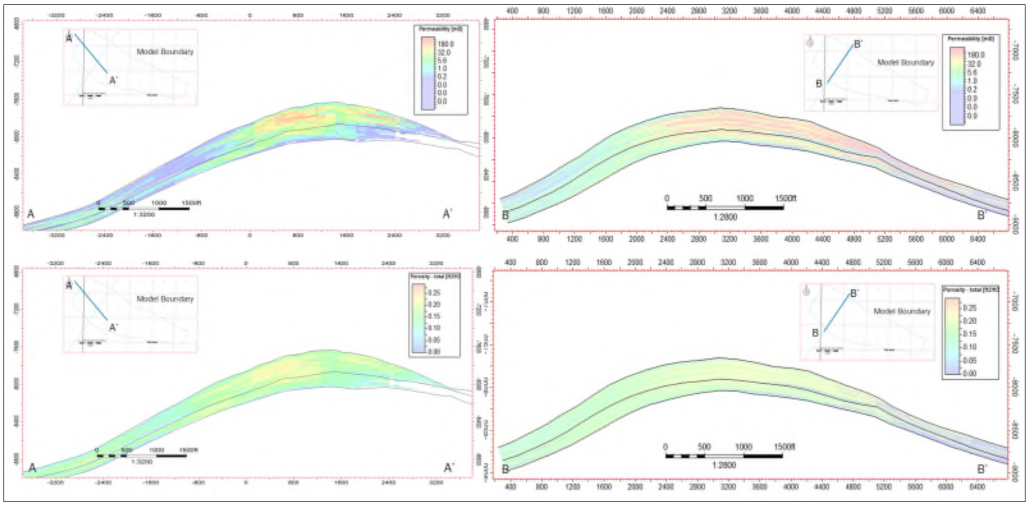


Figure 7 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 8 shows the permeability and porosity distribution in cross-section A-A'. Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

Figure 8: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

The Monterey Formation A1-A2 reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil 8,400	Oil - Water 8,550	
Saturation (fraction)	Water: 0.18 Gas: 0.82	Oil: 0.15 Water: 0.85	Water: 1.0

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability for the sand facies: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships and is elaborated further below. Figure 11 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permability data from wells 345A-35S and 367-7R. The functional form of the relative permeability curves are -

$krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))Nw$

$krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))Now$

krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))Nog
krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))Ng

With the parameters for the curve being -
Swcon - Endpoint Saturation: Connate Water = 0.38
Swcrit - Endpoint Saturation: Critical Water = 0.38
Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2
Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22
Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21
Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22
Sgcon - Endpoint Saturation: Connate Gas = 0
Sgcrit - Endpoint Saturation: Critical Gas = 0.05
krocw - Kro at Connate Water = 1
krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5
The end point relative permeabilities were then scaled by a factor of 0.1547 using the Oil-Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was then used in the simulation model.

The saturations at start of CO_2 injection were based on Material Balance calculations that were done for the A1-A2 reservoir. Material Balance is a well accepted method to determine the average saturations and fluid contacts in an oil and gas reservoir over time. Production and injection data recorded from 1973 up till 2020 was used in the Material balance. Pressure data obtained in the 2014-2015 timeframe in the Gas cap and the Oil legs of the reservoir were used to estimate an approximate current Gas-Contact at ~8400' (see Figure 10 below) and was also used to validate the material balance. The original Oil-Water contact was estimated at ~8550' based on reservoir delineation wells drilled in the 1970s, and as there was no sign of repressurization following the gas blowdown of the A1-A2 reservoir, the Oil-Water contact is estimated to have remained the same. The original oil in place estimate using this Oil-Water contact yielded a good material balance match with the current pressure data and cumulative production and injection associated with the A1-A2 reservoir.

Figure 9: Relative permeability data from core samples taken from 367-7R in the A1-A2 and from similar quality Monterey formation in 345A-35S.

Figure 10: Pressure data gathered during 2014-2015 timeframe which was used to estimate the approximate current Gas-Oil contact in the A1-A2 reservoir.

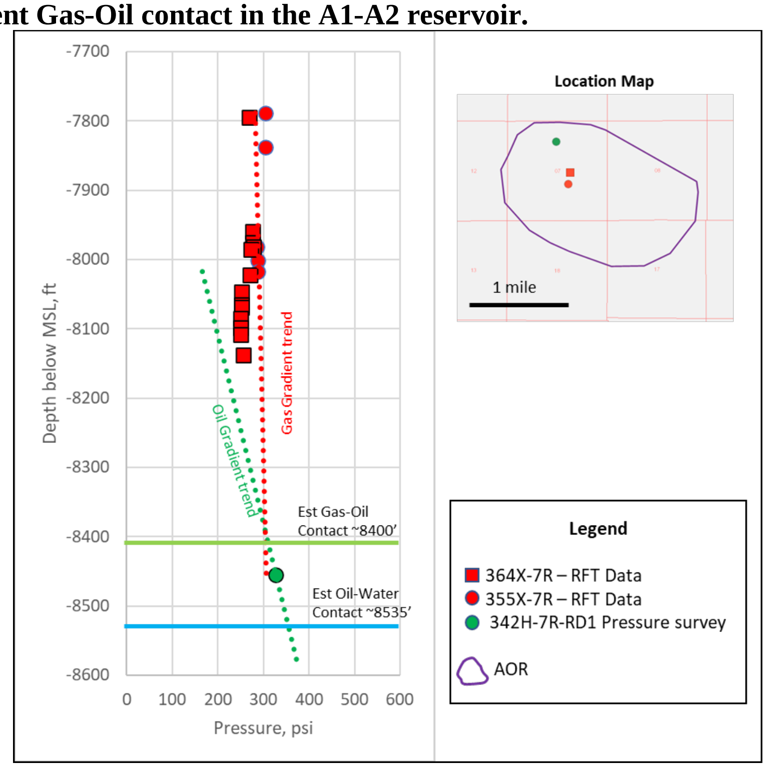
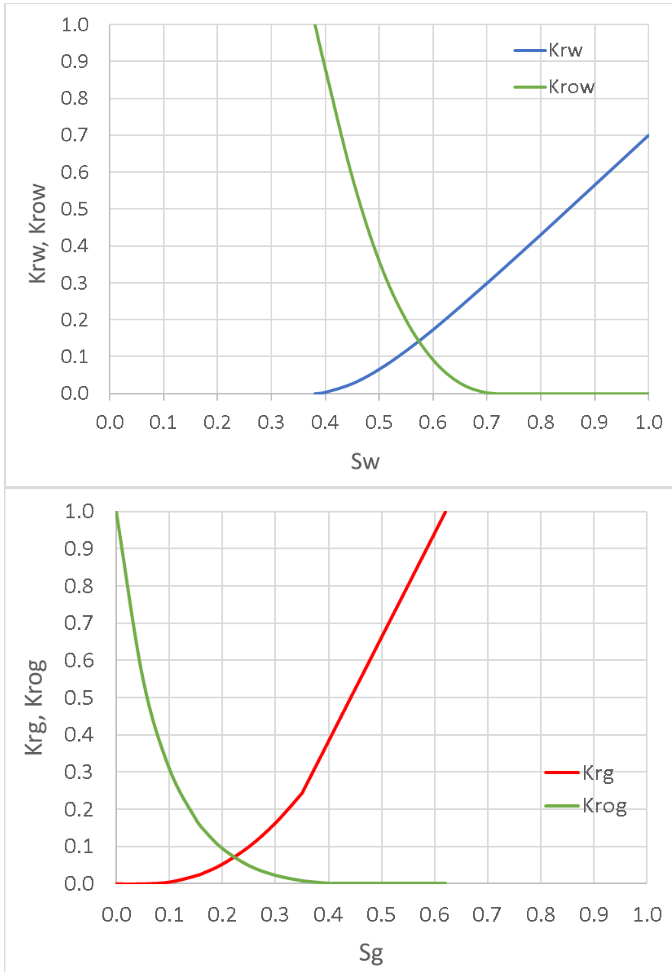


Figure 11: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study (krow = relative permeability oil in an oil-water system, krg = relative permeability to gas in a gas-oil system, krw = relative permeability to water in an oil-water system, and krog = relative permeability to oil in a gas-oil system).



Mineralization

Previous studies into reactive transport modeling and geochemical reaction in CCS have shown that the amount of CO_2 trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III of the Intergovernmental Panel on Climate Change) for sandstone reservoirs. For the sake of computational efficiency and the minor expected effect on the AoR, reactive transport was not included as a part of the compositional simulation modeling.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 12) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 12) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir gas cap is at 230 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. Formation pressure measurements taken, after the blow down of the A1-A2 reservoir, during the drilling of wells in the area show large pressure difference between the A1-A2 reservoir and the underlying A3-A11 reservoir, and the overlying Etchegoin formation. This supports the conclusion that the A1-A2 reservoir is hydraulically separate. Figure 13 shows the pressure data from wells in the area and their location with respect to the AoR. This data was gathered between 2007-2014 and is reflective of a period when there was limited production operations in the A1-A2 reservoir, waterflooding operations in the A3-A11 reservoir, and no production operations in the Etchegoin formation, and shows maintenance of large pressure differentials between the reservoirs, indicative of pressure isolation between them. Pressure data gathered over the range of the reservoir's productive life also supports this conclusion and is shown in Figure 14. Additional data will be gathered and provided to the EPA as a part of the preoperational testing once all operations in the A1-A2 have ceased, prior to CO2 injection, to further demonstrate pressure isolation between the reservoirs.

Figure 12: Monterey Formation A1-A2 production and injection data.

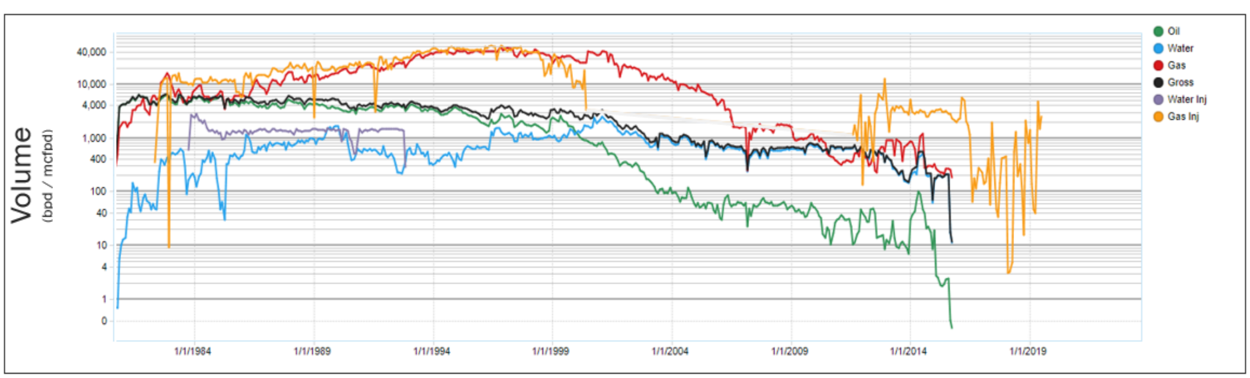


Figure 13: **(Left) Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated. The A3-A11 reservoir has been produced from since 1973 and the reservoir pressure has been reduced from initial conditions as a result. In comparison, the Etchegoin formation has not been produced in this area.**

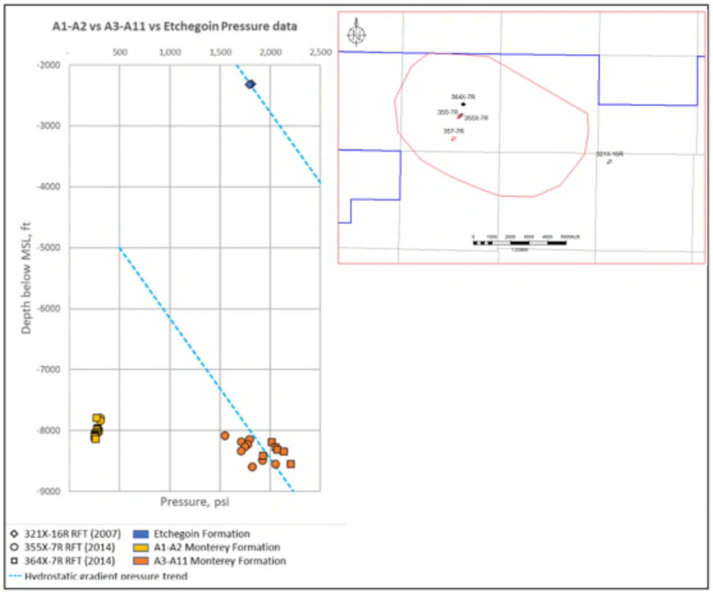
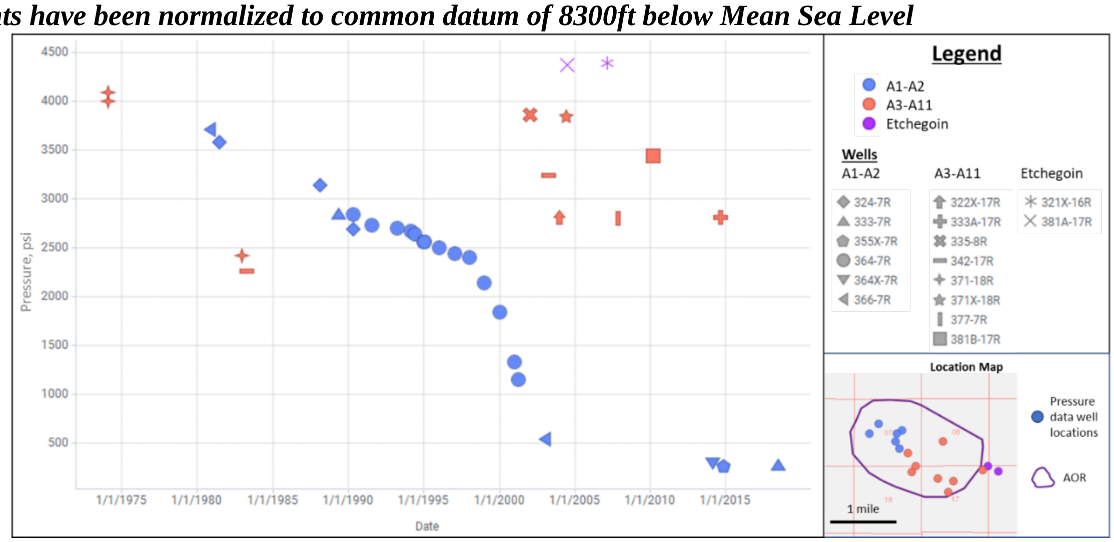


Figure 14: Formation pressure data in the area gathered from 1974 to 2017 showing the maintenance of pressure differentials between the A1-A2, A3-A11 and the Etchegoin formation. ***All the pressure points have been normalized to common datum of 8300ft below Mean Sea Level***



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation A1-A2 reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	240	Fahrenheit	8,300	Fluid Analysis
Formation pressure	200-300	Pounds per square inch	8,300	Pressure Test
Fluid density	61	Pounds per cubic foot	8,300	Water analysis
Salinity	25,000	Parts per million	8,300	Water analysis

Elevation of 8,300ft below MSL (Mean Sea Level) was used as a datum to initialize the model as it was a legacy datum depth used in historical data collection and study of the reservoir (corresponding to mid-point of the original Oil leg in the reservoir). This depth is in the current Gas Cap of the reservoir which is where the injectors are located and due to the high gas saturation where there is almost no Pressure variation with depth prior to injection. On initialization, the simulation model calculates the pressure, temperature, and fluid properties at every grid cell in the model. The injectors 357-7R and 355-7R are located and perforated in the Gas Cap of the A1-A2 reservoir, and as such the conditions at 8,300ft (below MSL) should be representative of the pressure and temperature at the injectors.

The base case was initialized using a uniform average temperature of 250^{o}F in the A1-A2 reservoir to be conservative. This was based on idle well temperature surveys taken between 2014 – 2017 within the AoR. A case was also run using a vertical temperature profile in the reservoir based on these idle well temperature surveys which predicted slightly higher storage capacity (~+4% higher) with minimal difference predicted in maximum required injection pressure. A case was also run using GEM's Thermal option to model heat balance and gauge if modeling reservoir temperature changes was necessary. The results indicated minimal effect on the system behavior (< 0.5% change in Total CO2 Injection capacity, < 0.5% deviation in reservoir pressure trend) and was thus not included in the base case and the sensitivities.

Fluid composition and model parameters

A ten component fluid model with some lumped components for heavier hydrocarbons was used for the simulation model with the composition shown in Table 5 for the Oil leg and Gas cap. Sensitivities were also run with varying compositions for the Gas cap (varying methane composition from 73% to 90%), but was not found to affect the injection pressures or storage volumes significantly (< 5% variance in storage capacity and < 0.5% variance in Injection pressures). The current oil composition in the oil leg was arrived at by taking the initial compostion of the reservoir oil at discovery conditions (shown in Attachment A, Figure 35), and then running a multiphase flash calculation to approximate current reservoir pressure using CMG's equation of state multiphase property calculation software – Winprop – to estimate the current composition of the Oil and Gas phases. The gas composition predicted during this flash calculation compared favorably to the 353-7R gas sample (Attachment A, Figure 36) and other recent A1-A2 gas samples, with the only major difference being in CO2 composition, as CO2 has been added to the gas cap through gas injection. The Equation of State (EoS) model parameters are shown in Tables 6.A-C.

Table 5: Model assumed Oil and Gas components and compositions in A1-A2 Gas cap and Oil Leg

Component	Oil Leg	Gas Cap
C1N2	2%	73%
CO2	0%	7%
C2H6	0%	3%
C3H8	2%	6%
C4	4%	5%
C5C6	8%	4%
C7-10	11%	2%
C11-19	26%	0%
C20-35	26%	0%
C35+	19%	0%

Table 6.A: Equation of state binary interaction coefficients. Cn (where n=1,2,3..) are hydrocarbons

Binary Interaction coefficients										
Component	**C1**	**CO2**	**C2**	**C3**	**C4**	**C5-C6**	**C7-10**	**C11-19**	**C20-35**	**C35+**
C1	0.0000	0.1039	0.0025	0.0083	0.0139	0.0204	0.0403	0.0625	0.0894	0.0573
CO2	0.1039	0.0000	0.1300	0.1250	0.1185	0.0700	0.0800	0.0800	0.1150	0.1450
C2	0.0025	0.1300	0.0000	0.0015	0.0045	0.0088	0.0179	0.0337	0.0548	0.1339
C3	0.0083	0.1250	0.0015	0.0000	0.0008	0.0032	0.0025	0.0061	0.0114	0.0243
C4	0.0139	0.1185	0.0045	0.0008	0.0000	0.0008	0.0036	0.0120	0.0262	0.0401
C5-C6	0.0204	0.0700	0.0088	0.0032	0.0008	0.0000	0.0011	0.0070	0.0190	0.0315
C7-10	0.0403	0.0800	0.0179	0.0025	0.0036	0.0011	0.0000	0.0027	0.0115	0.0222
C11-19	0.0625	0.0800	0.0337	0.0061	0.0120	0.0070	0.0027	0.0000	0.0033	0.0102
C20-35	0.0894	0.1150	0.0548	0.0114	0.0262	0.0190	0.0115	0.0033	0.0000	0.0020
C35+	0.0573	0.1450	0.1339	0.0243	0.0401	0.0315	0.0222	0.0102	0.0020	0.0000

Table 6.B: Jossi Stiel Thodos viscosity correlation parameters

Exponent Param	Polynomial Coeff 0	Polynomial Coeff 1	Polynomial Coeff 2	Polynomial Coeff 3	Polynomial Coeff 4
1	0.1023	0.0234	0.0585	-0.0477	0.0118

Table 6.C: EoS parameters for components

Component	Pc (Atm)	Tc (Deg K)	Acentric fact.	MW
C1	45.32	189.91	0.01184	16.04
CO2	72.85	304.22	0.231	44.01
C2	48.16	305.44	0.0908	30.07
C3	41.94	369.83	0.1454	44.09
C4	37.03	420.07	0.18764	58.12
C5-C6	32.97	480.81	0.25085	76.53
C7-10	29.66	572.09	0.29564	104.08
C11-19	21.82	680.17	0.465	166.19
C20-35	14.55	807.27	0.75433	287.98
C35+	10.05	931.32	1.09748	500

Operational Information

Details on the injection operation are presented in Table 7.

Table 7. Operating details.

Operating Information	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Location (global coordinates) X Y	 35.32802963 -119.5449982	 35.33139038 -119.5441437
Model coordinates (ft) X Y	 6,100,956.63 2,308,944.30	 6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft TVD/ ft MSL / ft MD) Top Bottom	 8,511 / 7719 / 8520 8,793 / 8001 / 8802	 8,483 / 7769 / 8488 8,658 / 7944 / 8663
Wellbore diameter (in.)	7	7
Planned injection period Start End	 02/01/2024 04/01/2039	 02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	530-794	530-794

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

Tests have been conducted in the history of the reservoir to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field. A 0.82 PSI/foot fracture gradient for the Monterey Formation A1-A2 reservoir was obtained from well 327-7R-RD1. CTV will conduct a step rate test for the Reef Ridge Shale as per the pre-operational testing plan.

CTV will ensure that the injection pressure is beneath 90% of the fracture pressure at the top perforation in the injection wells (shown in Table 8) calculated using a 0.82psi/ft fracture gradient, which is 6,281psi and 6,260psi for 357-7R and 355-7R respectively. Further details on injector operating parameters are provided in the "355-7R Operating Procedures" and "357-7R Operating Procedures" attachments.

Table 8. Injection pressure details.

Injection Pressure Details	Injection Well 1 357-7R	Injection Well 2 355-7R
Fracture gradient (psi/ft)	0.82	0.82
Maximum bottomhole injection pressure (90% of fracture pressure) (psi)	6,281	6,260
Elevation corresponding to maximum injection pressure (ft TVD)	8,511	8,483
Elevation at the top of the perforated interval (ft TVD)	8,511	8,483
Average bottom hole injection pressure at top of perforations (psi)	2302	2423
Average bottom hole injection gradient at top of perforations (psi/foot)	0.27	0.28

Computational Modeling Results

Predictions of System Behavior

The Base case simulation was for 15 years of injection with a total of 145 BSCF (7.7 MMT) of CO2 injected, taking the pore volume average reservoir pressure back up to discovery pressure of 4000psi. The Simulation was run for a total period of 115 years (15 years of injection and 100 years of post-injection).

Currently a 100% CO2 injectate stream was assumed for the simulation studies. Table 9 summarizes the expected properties of the injectate at reservoir conditions at the low pressure start of the project and at the higher pressure end of the project.

Table 9: Injectate property at average reservoir conditions at start and end of project

Injectate Property	At start of injection	At end of injection
Viscosity, cp	0.020	0.046
Density, lb/ft3	3.12	34.39
Salinity, ppm	NA	NA
Compressibility factor, Z	0.933	0.674
Fluid Compressibility, psi^{-1}	0.0022	0.0002

The following maps (Figure 15) and cross-sections (Figure 16) show the computational modeling results and development of the CO_2 plume at seven time-steps. The boundaries of the AoR have been defined with a 3% CO_2 global mole fraction cutoff. The maximum vertical and lateral extent of the CO_2 plume is within the first year of post-injection, at which time the plume largely stabilized. The reservoir quickly becomes stable because the most significant trapping mechanism is structure. For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The majority of the CO2 is predicted to remain in Section 7 as shown in Figure 15. The simulation predicts minor amounts of CO2 in the shale dominated updip portion of the reservoir in Sections 8 and 17 (Central and Eastern portion of the AoR boundary) due to minor potential connected sand lenses modeled in the geomodel. This is a conservative interpretation and resulting AoR. In reality, it is likely that CO2 may not migrate to these areas due to those sand lenses not being sufficiently connected.

Figure 15A: Plan view showing the plume development in mole percent CO2 through time for layer 15. Red dots ae the injectors, Blue dots are monitoring wells. Sections 8 and 17 have CO_2 in small quantities due to minor potential connected sand lenses, as the reservoir becomes shale dominated up-dip. It is highly unlikely that CO_2 will migrate to these areas.

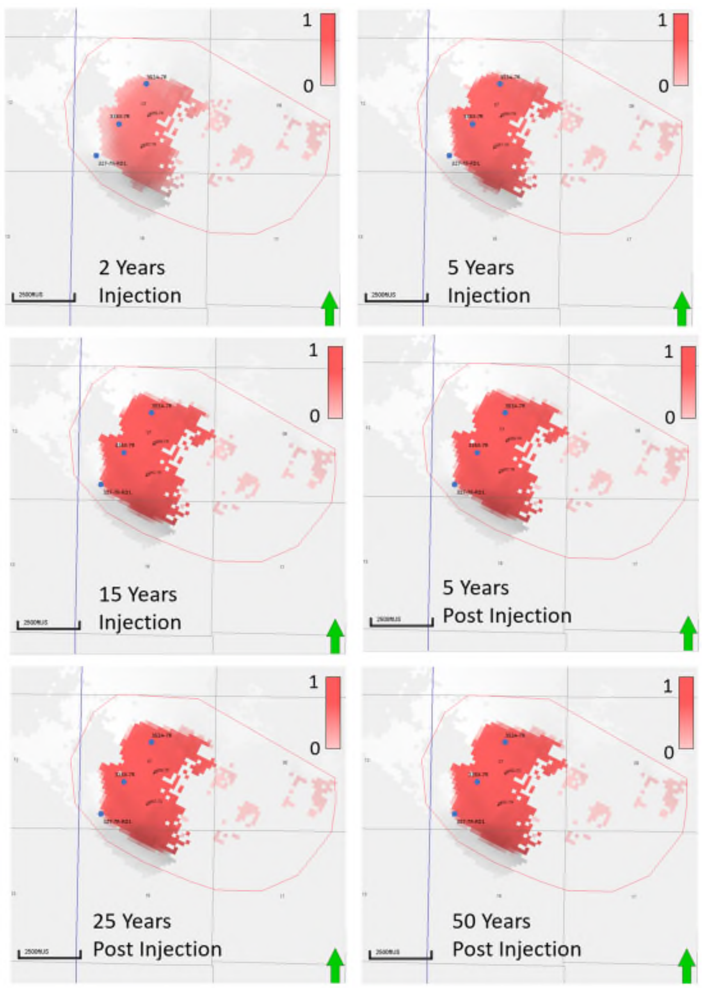


Figure 15B: Plan view showing the gas saturation changes through time for layer 15. Red dots ae the injectors, Blue dots are monitoring wells.

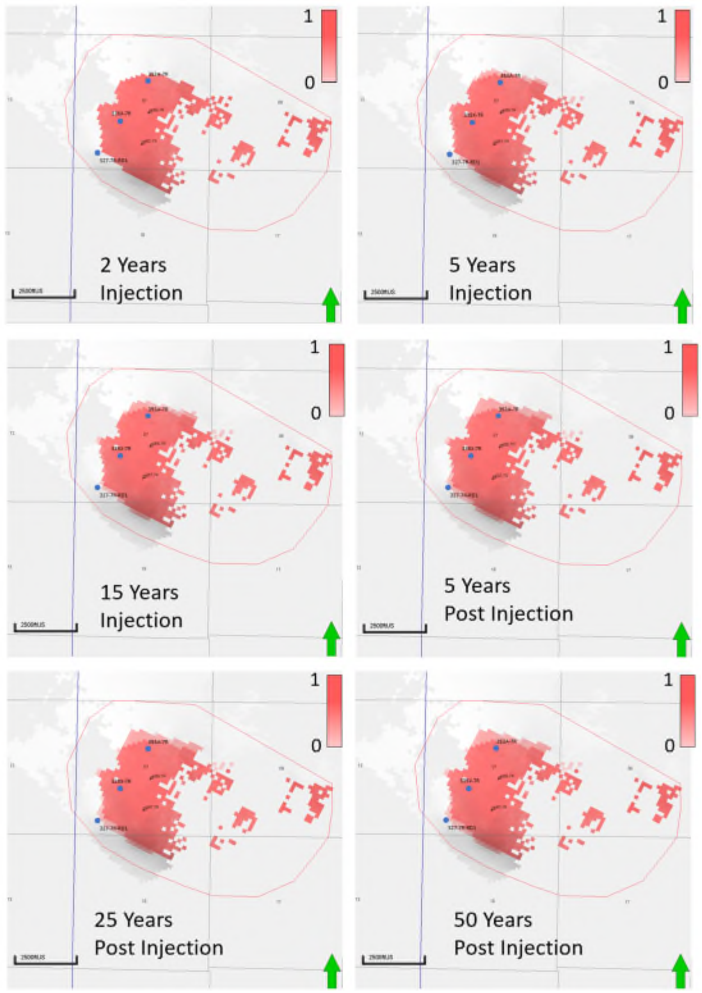
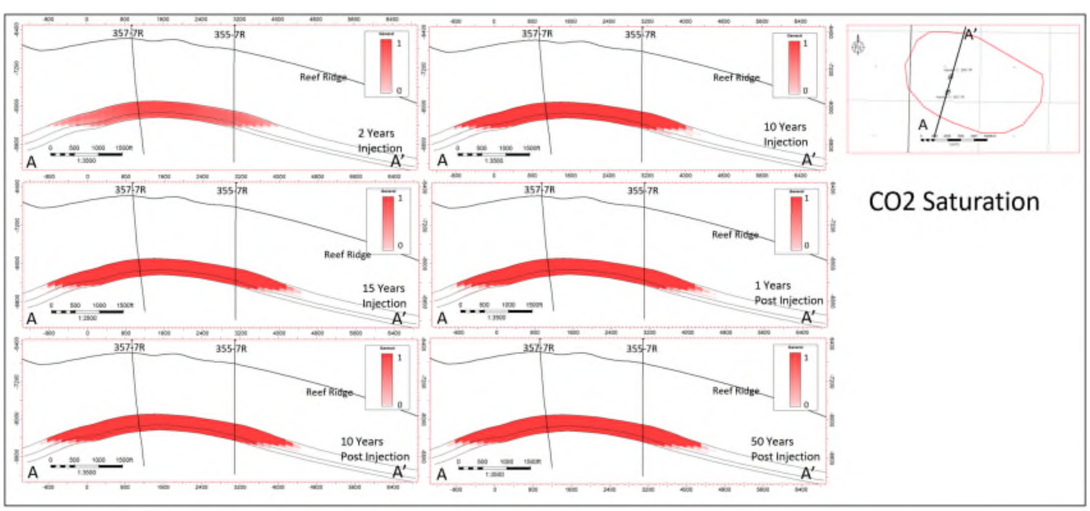
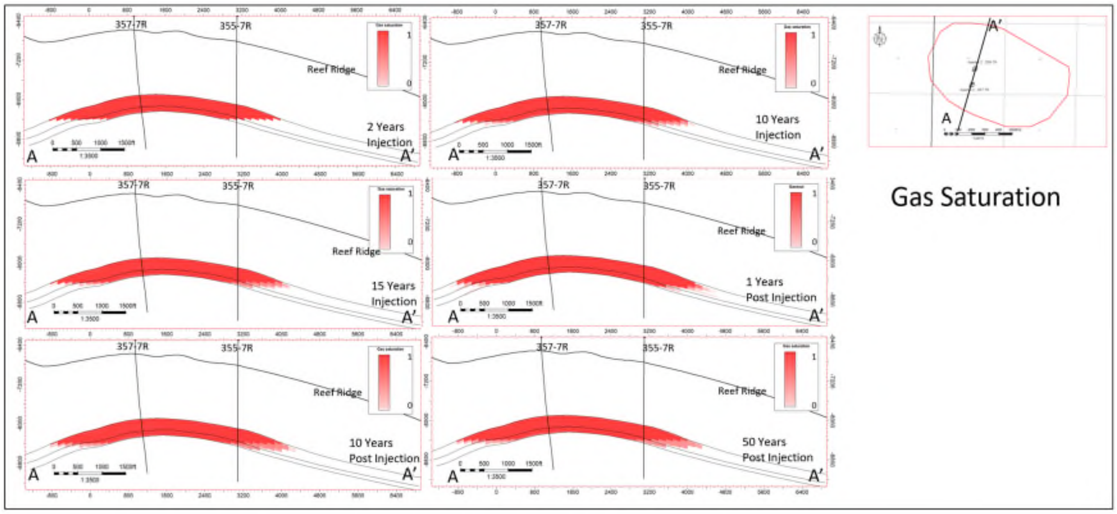


Figure 16: Cross-sections showing the plume development through varying times through the project as gas saturation and CO2 saturation.

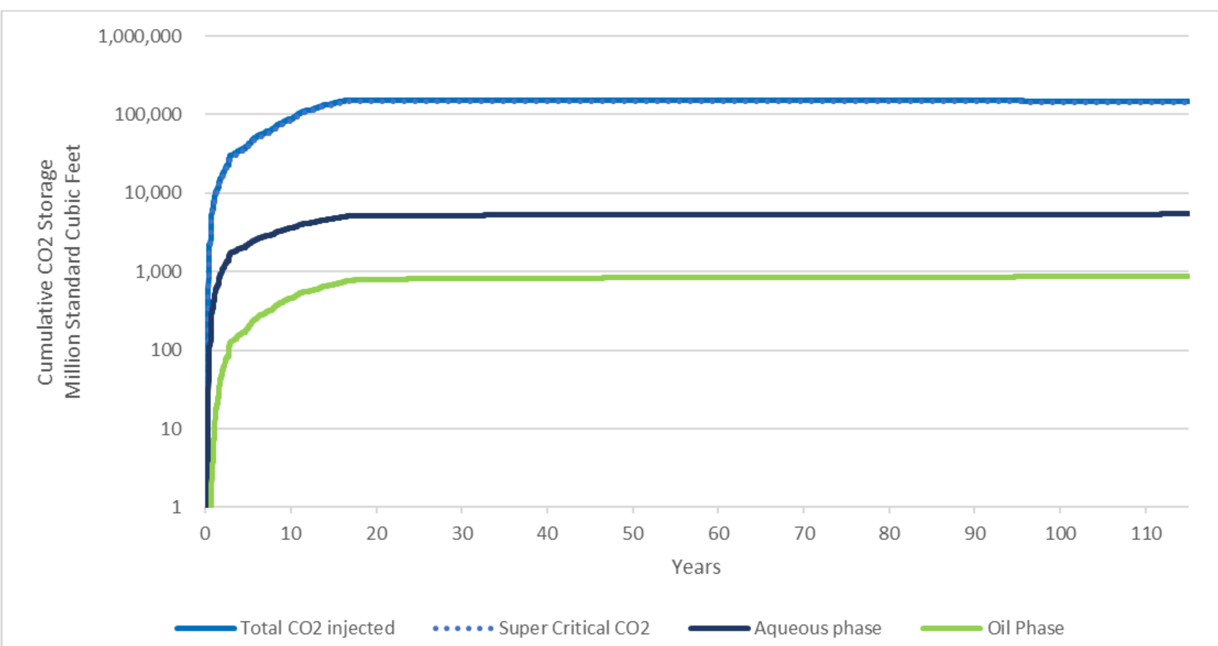




CO_2 injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining saturation for oil and water in the depleted reservoir, majority of the CO2 is stored as Supercritical phase and there is little change in storage mechanism after the end of injection. 100 years after the end of injection 96% of the CO2 is still in the Supercritical phase, with only 3.5% in dissolved in the Aqueous phase and 0.5% in the Oil Phase.

Figure 17 shows the Cumulative storage for each of the mechanisms over the 15 year injection period and 100 years after the end of injection.

Figure 17: CO2 storage mechanisms in the reservoir. Note that since majority of the CO2 is in the Supercritical phase, the Total CO2 injected (blue line) and Super Critical CO2 (dotted blue line) are almost identical on the graph.



Model Calibration and Validation

CRC has injected 175 BCF of gas into the Monterey Formation A1-A2 reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The Base case simulation was run for 15 years of injection. This represents the anticipated project duration and rate. In addition, a scenario was also run with 5 years of injection at a much higher injection rate. Both scenarios were run for 100 years post injection to verify plume stabilization. There was no difference in AoR extent or storage volume between the scenarios.

As a computational model sensitivity, CTV also ran a scenario where high injection rate was maintained for nine years, with an increase of the post-injection pressure and total CO_2 injected. At a final reservoir pressure of 5,750 psi, versus base case of 4,000 psi final reservoir pressure, the reservoir can store 193 BCF of CO_2. Figure 18 shows the difference in plume development at 100 years post injection. Note that the plume stays within the AoR, with increased CO_2 concentrations in cells in northwestern portion of the AoR.

Additionally, the scenarios listed in the Table 10 were run varying major inputs to the simulation to see whether it had any significant impact on the AoR boundary. The results from the different scenarios were reviewed and showed varying final CO2 storage amount but no impact to the AoR boundary.
To determine if near field effects were being adequately captured, a version of the model with Local Grid refinement (LGR) around the injectors was run with a finer X-Y grid dimension of 15 ft by 15 ft in the ~5 acre area around the injectors. The results for this case compared favorably with the Base case, and the predicted maximum bottom hole pressure for the LGR case was within 0.2% of the Base case, with no impact to the AoR boundary predicted.

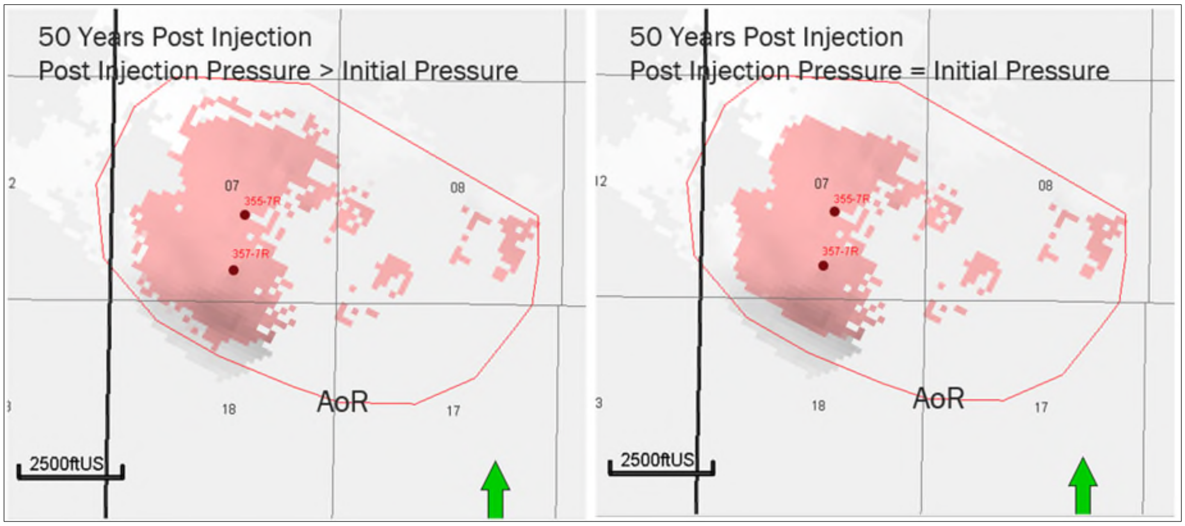
A conservative fixed permeability anisotropy ratio (Vertical permeability / Horizontal permeability or kv-kh ratio) of 0.1 was applied uniformly to the grid in the Base case. Range of the potential anisotropy ratio to use was estimated based on upscaling the log derived permeability (which were calculated at a 0.5 ft resolution) to the grid level of ~10ft resolution and then using an arithmetic mean to estimate horizontal permeability and a harmonic mean to estimate vertical permeability. The analysis estimated a wide range for anisotropy with a P10 – P90 range of 0.1 to 0.9. A sensitivity case run using a 0.9 permeability anisotropy, indicated negligible difference to storage capacity, injection pressures and plume shape.

Table 10: Simulation sensitivity scenarios

Scenario	AoR impact
Base Case: (15yrs of injection)	Base AoR
High Injection rate scenario (5yrs of injection)	No impact to AoR
Higher final reservoir pressure scenario	No impact to AoR
NTG : 10% reduction from base case	No impact to AoR
Porosity: 10% reduction from base case	No impact to AoR
Porosity: 10% increase from base case	No impact to AoR
Permeability: 10% reduction from base case	No impact to AoR

Permeability: 10% increase from base case	No impact to AoR
Grid XY dimensions: reduced to 75'x75'	No impact to AoR
Local grid refinement around injectors to 15'x 15'	No impact to AoR
Permeability anisotropy, kv-kh ratio = 0.9	No impact to AoR
Gas cap composition range (73% to 90% Methane)	No impact to AoR

Figure 18: Plan view of plume development at layer 15 in the computational model.



These scenarios demonstrate that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent for a range of scenarios. This provides confidence that the corrective action well review and potential impact to the Upper Tulare USDW is conservative and has been appropriately evaluated.

Stochastic analysis of impact of reservoir parameters

In addition to the sensitivity cases considered in the previous section, a stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 100 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 8.3MMT, with a P10 of 7MMT and a P90 of 9.3MMT, which is within our expected range.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.8 - 1.3	Normal distribution	Multiplier range used to have grid mean value range of 0.13 - 0.2

Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~6 - 60md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Truncated normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation A1-A2 reservoir until the reservoir pressure reached the discovery pressure of 4,000 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

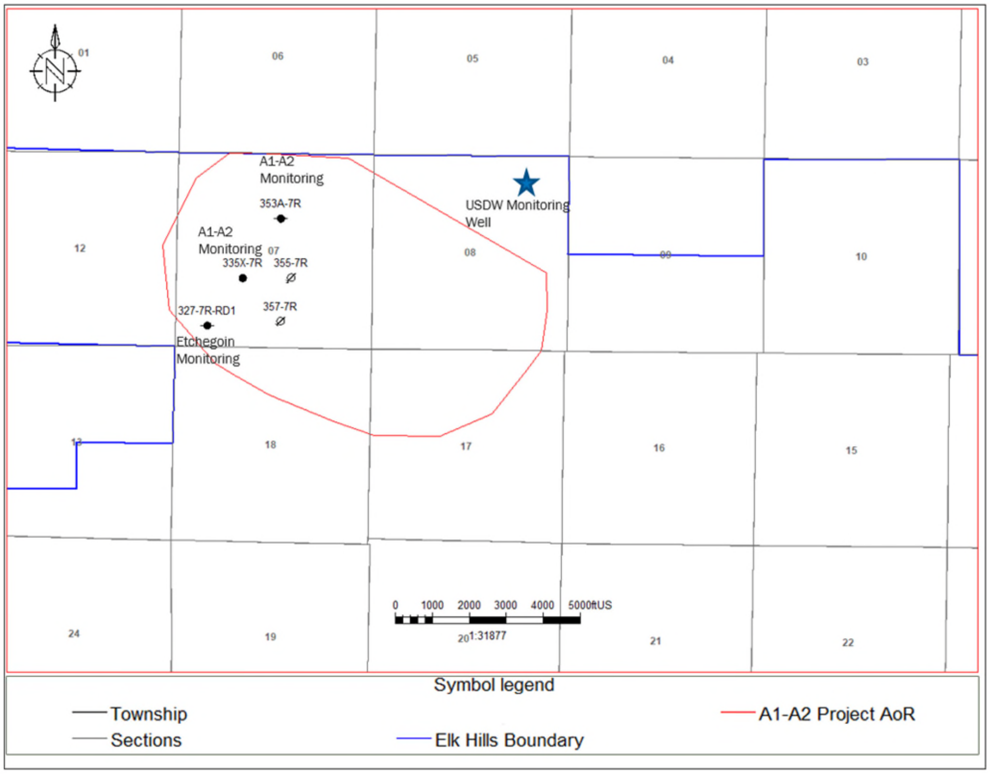
Figure 19 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



<u>Corrective Action</u>

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation A1-A2 reservoir was discovered in 1973 and developed subsequently. As such, there are excellent records for wells drilled in the field. There have been no "un-documented" historical wells found during the over 40-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications.

Tables 12 and 13 provide counts of the AoR wellbores by status and type, for each wellbore with a unique API-12 identifier. Appendix 1 provides a complete list of all API-12 wellbores within the AoR. As required by 40 CFR 146.84(c)(2), the well table in Appendix 1 describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to the A1-A2 injection zone, record of plugging, requirement for corrective action, if necessary. CTV also identifies well work to be completed during the pre-operational testing phase.

Table 12: Wellbores in the AoR by Status

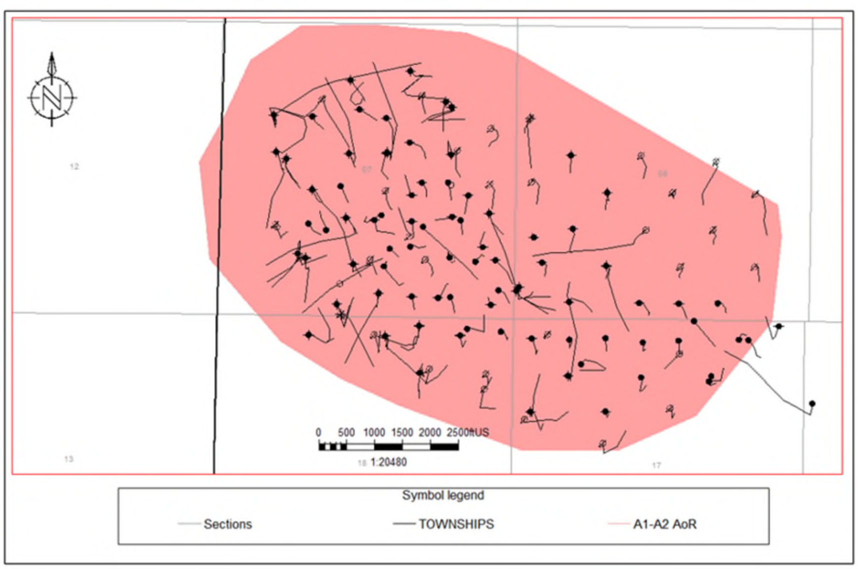
Status	Count
Active	41
Idle	70
Plugged and Abandoned	39
Total	**150**

Table 13: Wellbores in the AoR by Type

Type	Count
Oil & Gas Producing Wells	79
Class II Injection/Disposal Wells	32
Observation Wells	0
Plugged and Abandoned	39
Total	**150**

All wells that are currently operating in the A1-A2 reservoir will cease operations and wells not associated with the project will be abandoned prior to injection. As such, they will not affect the AoR delineation. Wells in the AoR with an active status are development wells completed below the Monterey Formation A1-A2 reservoir and associated with a CalGEM Class II approval within the A3-A11 sand intervals.

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation A1-A2 sequestration reservoir reviewed for corrective action.



Protection of USDW

For the Elk Hills A1-A2 Storage Project, CTV assessed USDW protection by evaluating all wellbores that penetrate the confining Reef Ridge Shale. All wells within the AoR meet the criteria below, ensuring protection of the USDW:

1. Surface or intermediate casing over the USDW
2. If well is abandoned, cement plug across base of USDW
3. Cement in the annulus:
    a. Intermediate casing – cement above the above the surface casing shoe.
    b. Sufficient annular cement within the confining Reef Ridge Shale.

Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Reef Ridge Shale confining zone.

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q1 2021.

Monterey Formation A1-A2 Isolation

Wells that will not be used for the Elk Hills A1-A2 Storage Project that penetrate and are currently perforated in the Monterey Formation A1-A2 will be abandoned prior to injecting CO_2. These wells have not been deemed deficient, and they will not be used for hydrocarbon production from the A3-A11 underlying sands. The abandonment of these wells is considered to be normal operating procedures to manage and minimize liabilities. Wellbores that meet this criteria are included in the 33 wells identified for abandonment in Appendix 1.

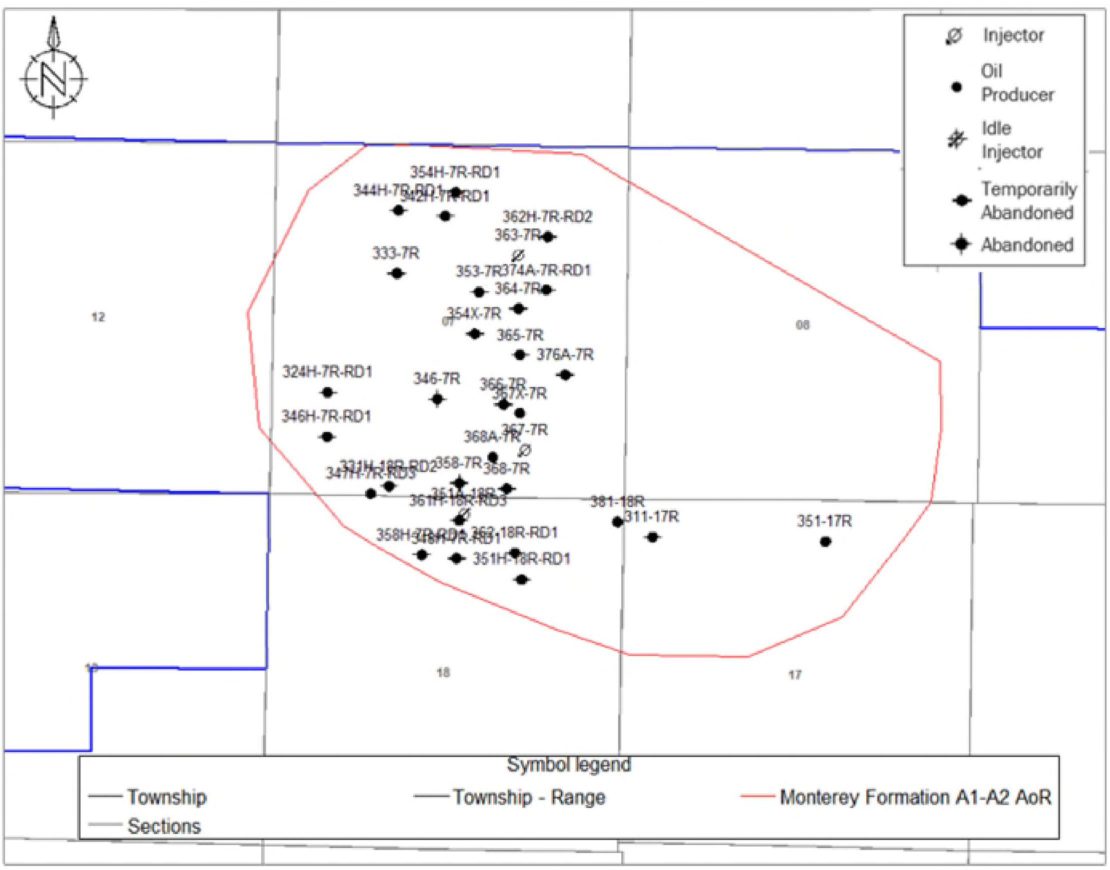
Wells that pass through and are not completed in the A1-A2 sand serve to either inject into or produce from some combination of the A3-A11 sands. All pass through wells not planned for abandonment during pre-operational testing have been determined to be adequately isolated from A1-A2 sands.

Corrective Action Assessment of Wells in AoR

The corrective action assessment included the generation of detailed casing diagrams for each wellbore, review of all perforations, assessment of cement tops for each casing string, and determination of cement plug depths. CTV can demonstrate that the USDW is protected and that with the abandonment of 33 wells (Figure 21), the Monterey Formation A1-A2 reservoir will be isolated. Annular cement and cement plugs within the casing will be placed within the Reef Ridge confining layer so as to re-establish caprock integrity.

Appendix 2 provides the plugging procedure that will be used to abandon these wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. Additionally, the procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Figure 21: Wells to be abandoned prior to injection.



Plan for Site Access

CTV operates and owns 100% of the surface, mineral, and pore space rights for the project where all activities will take place. As such, site access has been guaranteed for the duration of the project and for post-injection monitoring.

Corrective Action Schedule

Corrective action for all wells withing the AoR will be completed before CO_2 is injected in the reservoir. This will ensure that CO_2 is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.
7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.
2. Difference between the computation modeling and observed plume development:
    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.
    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a variance >±10% from the Base Case Simulation.
    c. Any other activity prompting a model recalibration.
3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:
    a. The presence of faults near the confining zone that indicates propagation into the confining zone.
    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event