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

Clean Energy Systems Mendota

1. Facility Information

Facility name:	CLEAN ENERGY SYSTEMS MENDOTA_INJ_1
Facility contact:	Rebecca Hollis 400 Guillan Park Drive, Mendota, CA 93640 Office: 916-638-7967
Well location:	MENDOTA, FRESNO COUNTY, CA T13S R15E S32 LAT/LONG COORDINATES (36.75585015/-120.36440423)

This attachment is one of the several documents listed below that was prepared by Schlumberger and delivered to Clean Energy Systems. These documents were prepared to support the Clean Energy Systems preconstruction application to the EPA.

- Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions (Schlumberger, 2021a)
- Attachment B: Area of Review and Corrective Action Plan (Schlumberger, 2021b)
- Attachment C: Testing and Monitoring Plan (Schlumberger, 2021c)
- Attachment D: Injection Well Plugging Plan (Schlumberger, 2021d)
- Attachment E: Post-Injection Site Care and Site Closure Plan (Schlumberger, 2021e)
- Attachment F: Emergency and Remedial Response Plan (Schlumberger, 2021f)
- Attachment G: Construction Details Clean Energy Systems Mendota (Schlumberger, 2021g)
- Attachment H: Financial Assurance Demonstration (Schlumberger, 2021h)
- Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota (Schlumberger, 2021i)
- Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j)

Contents

List of Figures

List of Tables

1.1 Abbreviations

AoR: area of review
BFW: below free water
BS: below surface
CalGEM: California Geologic Energy Management Division
CES: Clean Energy Systems
CSG: casing
DOGGR: California Division of Oil, Gas, and Geothermal Resources (as of 2020, CalGEM)
EPA: Environmental Protection Agency
GL: ground level
KB: kelly bushing
Mendota_ACZ_1: above-confining-zone monitoring well
Mendota_INJ_1: proposed CO_2 injection well
Mendota_OBS_1: injection zone monitoring well
Mendota_USDW_1: USDW monitoring well
MD: measured depth
MIT: mechanical integrity test
MSL: mean sea level
PISC: post-injection site care
P&A: plug and abandon
ppm: parts per million
PVC: pore volume compressibility
SCAL: special core analysis
sk: sack
TD: total depth
TDS: total dissolved solids
USDW: underground sources of drinking water
UIC: underground injection control
VSP: vertical seismic profile

1.2 Symbols

α^{-1}: entry pressure
ΔPc: critical pressure (Eq. 2)
ρi = fluid density of the injection zone
ρu = fluid density of the lowermost USDW
ξ = linear density gradient (coefficient) defined as

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i}$$

amix: attraction parameter
bmix: repulsion parameter
g: acceleration due to gravity
k: permeability
k_{rw}: relative permeability of brine
k_{rg}: relative permeability of CO_2
k_{rg} at S_{wir}: endpoint relative permeability of CO_2
P_c: capillary pressure
S_e: effective saturation
S_w: water saturation
S_{gir}: irreducible gas saturation
S_{wir}: irreducible water saturation
T_K: temperature in Kelvin
V: molar volume
z_i: elevation of the injection zone
z_u: elevation of the lowermost USDW

Disclaimer

Any interpretation, research, analysis, data, results, estimates, or recommendation furnished with the services or otherwise communicated by Schlumberger to Clean Energy Systems at any time in connection with the services are opinions based on inferences from measurements, empirical relationships and/or assumptions, which inferences, empirical relationships, and/or assumptions are not infallible, and with respect to which professionals in the industry may differ. Accordingly, Schlumberger cannot and does not warrant the accuracy, correctness, or completeness of any such interpretation, research, analysis, data, results, estimates, or recommendation. Clean Energy Systems acknowledges that it is accepting the services "as is", that Schlumberger makes no representation or warranty, express or implied, of any kind or description in respect thereto. Specifically, Clean Energy Systems acknowledges that Schlumberger does not warrant that any interpretation, research, analysis, data, results, estimates, or recommendation is fit for a particular purpose, including but not limited to compliance with any government request or regulatory requirement. Clean Energy Systems further acknowledges that such services are delivered with the explicit understanding and agreement that any action taken based on the services received shall be at its own risk and responsibility and no claim shall be made against Schlumberger as a consequence thereof.

To the extent permitted by applicable law, Clean Energy Systems shall not provide this report to any third party in connection with raising finance or procuring investment (other than pursuant to an equity capital raising on a public market) without a No Reliance Letter first being completed and signed by the third party and provided to Schlumberger. The form of the No Reliance Letter being agreed to by both Clean Energy Systems and Schlumberger. Subject to this requirement and upon full payment of applicable fees, copyright ownership in this report shall vest with Clean Energy Systems. Schlumberger grants no title or license or right to Clean Energy Systems to use Schlumberger’s Intellectual Property except as necessary for Clean Energy Systems to use the report.

Copyrights

Trademarks

All companies or product names mentioned in this document are used for identification purposes only and may be trademarks of their respective owners. An asterisk (*) denotes a mark of Schlumberger.

2. Computational Modeling Approach

The Mendota model was developed to evaluate the area of review (AoR) and risks associated with geological storage of injected CO_2 into the subsurface. The reservoir simulation was developed and performed by Schlumberger using the Petrel* software platform and ECLIPSE* 300 multiphase simulator. The Petrel platform was used to allow data from various domains (geology, geophysics, geomechanics, and reservoir engineering) to be incorporated into the model.

2.1 Model Background

2.1.1 Model Name and Authors/Institution

The ECLIPSE 300 (v2018.2) reservoir simulator with the CO2STORE module from Schlumberger was used for modeling.

2.1.2 Description of Model

ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO2STORE module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (i.e., "liquid"), a CO_2-rich phase (i.e., "gas"), and a solid phase, which is limited to several common salt compounds (e.g., NaCl, $CaCl_2$, and $CaCO_3$). Mutual solubilities and physical properties (e.g., density, viscosity, enthalpy, etc.) of the H_2O and CO_2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperature ranges between 12°C and 100°C and pressures up to 60 MPa. Details of this method can be found in Spycher and Pruess (2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The CO_2-rich phase (i.e., gas) density is obtained by using the Redlich-Kwong equation of state. The model was accurately tuned and modified as further described below (Redlich-Kwong, 1949).
- The brine density is first approximated as pure water then corrected for salt and CO_2 concentration by using Ezrokhi's method (Zaytsev & Aseyev, 1993).
- The CO_2 gas viscosity is calculated per the methods described by Fenghour et al. (1998).

The gas density was obtained using a modified Redlich-Kwong equation of state following a method developed by Spycher and Pruess, where the attraction parameter is made temperature dependent:

$$P = \left(\frac{RT_K}{V - b_{mix}}\right) - \left(\frac{a_{mix}}{T_K^{1/2} V(V + b_{mix})}\right) \quad (1)$$

where V is the molar volume, P is the pressure, T_K is the temperature in Kelvin, R is the universal gas constant, and a_{mix} and b_{mix} are the attraction and repulsion parameters.

The transition between liquid CO_2 and gaseous CO_2 can lead to rapid density changes of the gas phase; the simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

Because the compression facility controls the CO_2 delivery temperature to the injection well between 60°F and 120°F, the temperature of the injectate will be comparable to the reservoir formation temperature within the injection interval; therefore, the simulations were carried out based on isothermal operating conditions. With respect to timestep selection, the software algorithm optimizes the timestep duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, timestep size ranged from 8.64×10^1 to 4.32×10^6 seconds or 0.001 to 50 days. In all cases, the maximum solution change over a timestep is monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of temperature and pressure calculation results occur on successive iterations. New timesteps are chosen so that the predicted solution change is less than a specified target.

2.2 Site Geology and Hydrology

A detailed description of the site geology and site hydrogeology is provided in the permit application narrative (Schlumberger, 2021i). Associated figures including geologic maps, hydrologic maps, cross sections, and local stratigraphic columns are also included there.

2.3 Model Domain

The static geologic model includes the entire Panoche formation and the overlying seal (the Moreno shale), spanning a 19 mile × 19 mile area. The grid cells used are 500 ft horizontal by 4 feet vertical, which is consistent within the model domain. A smaller horizontal grid cell size will be used when detailed 3D seismic data are available to justify higher resolution. The entire model domain contains 64 million cells. The model domain was generated in the Petrel platform. Associated figures displaying map views and cross-sectional figures showing the horizontal and vertical extent of the model grid are discussed in the permit application narrative (Schlumberger, 2021i).

A subset of the heterogeneous reservoir model covering a 11.4-mile × 11.4-mile area with the injection well centered in the model domain (Figure 1) was used for the dynamic modeling. Model domain information is summarized in Table 1. To reduce the number of cells and optimize simulation run times, grid/property upscaling is typically applied. In this work, a Tartan grid was applied in the dynamic model as shown in Figure 1 to reduce the number of cells for dynamic simulations while maintaining the resolution around the injection well. Starting from Garzas at top, the global tartan grid configuration is 53 × 53 ×446 cells (totaling 1,252,814 cells) in the x, y, and z direction, respectively, with variable cell sizes. The smallest grid cells around the injector and observation well are 60 ft × 60 ft laterally. Vertical thickness of each cell within the model depends on the vertical proportion of each formation. Model domain information is summarized in Table 1.

Table 1. Model domain information.

Coordinate system	State Plane		
Horizontal datum	NAD 27		
Coordinate system units	feet		
Zone	SPCS27_0404		
FIPSZONE		**ADSZONE**	
Coordinate of X min	1570305.76	**Coordinate of X max**	1630305.76
Coordinate of Y min	490689.19	**Coordinate of Y max**	550688.99
Elevation of bottom of domain	-16042.75	**Elevation of bottom of domain**	-4073.92

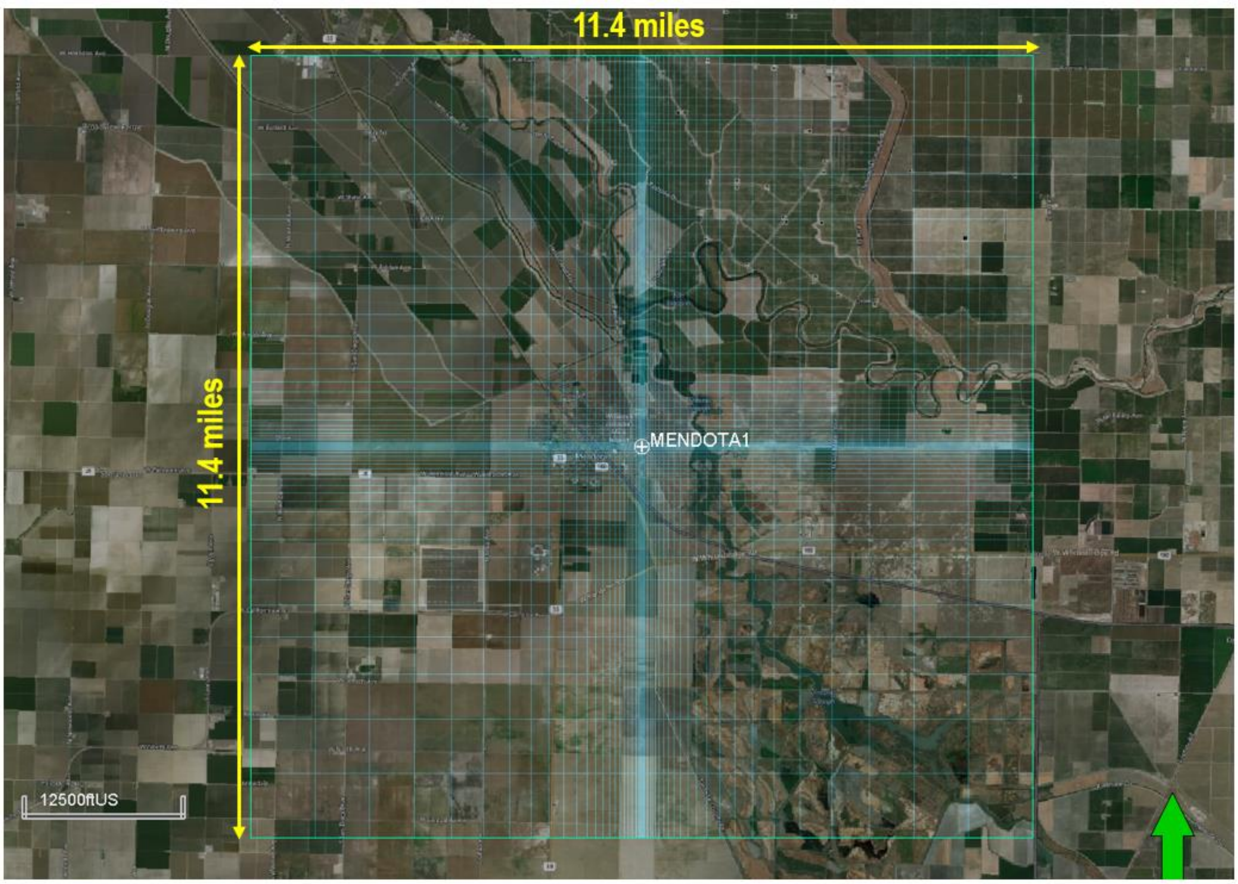

Figure 1. Dynamic model domain and tartan grid.

2.4 Porosity and Permeability

A detailed description of the porosity and permeability of the static model is provided in the (Schlumberger, 2021i). Associated figures include maps, cross sections, and 3D figures of the porosity or permeability distribution within the model domain. There are also statistical plots (histograms and cross plots) to show the porosity and permeability characteristics for each formation. For the dynamic modeling, upscaling in the petrophysical properties was applied to the tartan grid. Figure 2 shows the locations of the cross-sections in Figure 3 and Figure 4. Figure 3 illustrates the upscaled porosity profile along the N-S cross-section, and upscaled permeability along the E-W cross section is shown in Figure 4. Vertical permeability is assumed to be equal to 10% of the horizontal permeability.

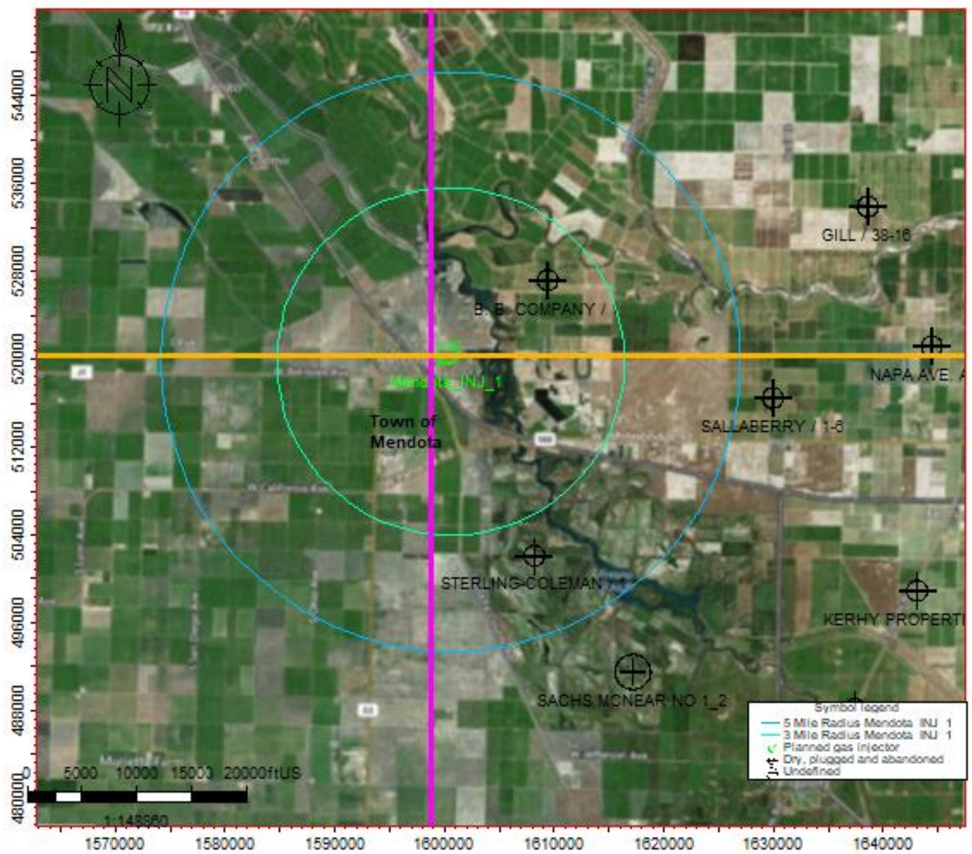

Figure 2. Injection well cross-section traverse map, N-S (violet) and E-W (orange). The black wells represent wells where petrophysical analysis was performed.

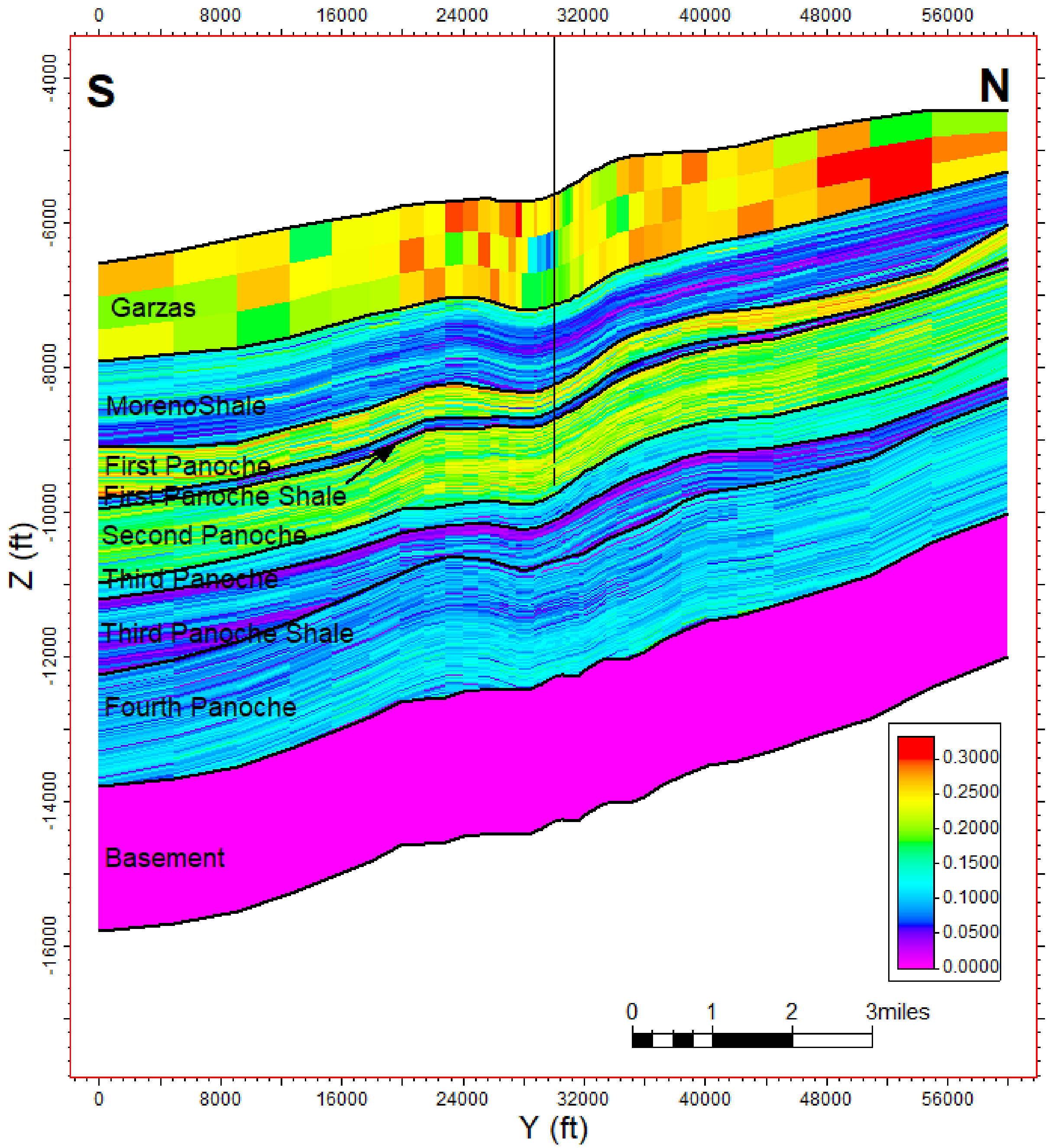

Figure 3. Upscaled porosity profile along the N-S cross-section. Vertical exaggeration is 5x.

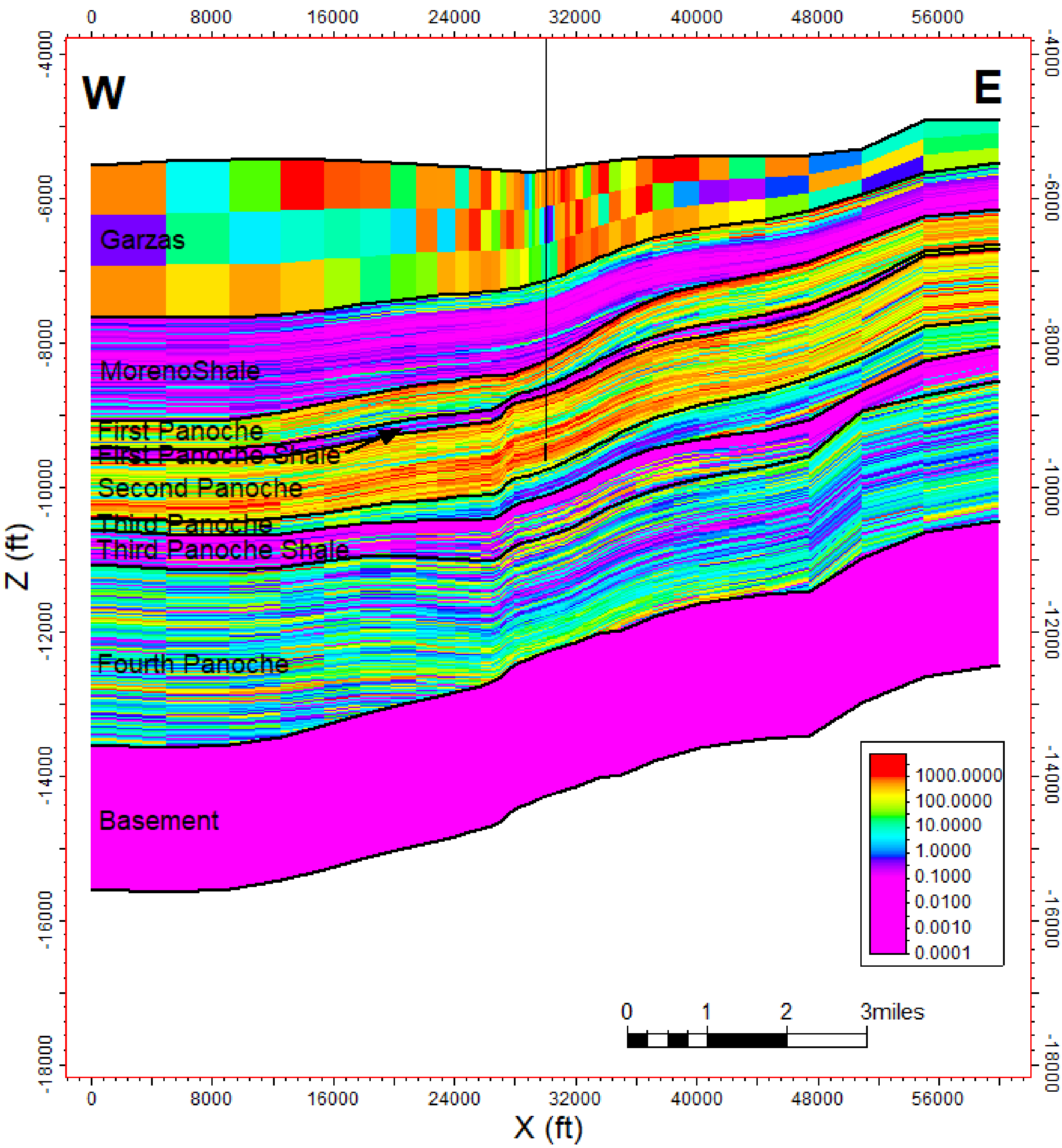

Figure 4. Upscaled permeability profile along the E-W cross-section. Vertical exaggeration is 5x.

2.5 Constitutive Relationships and Other Rock Properties

Two rock types (sand and shale) were used to assign relative permeability and capillary pressure curves. Figure 5 is the crossplot of porosity against log permeability (log *k*). Neural network training method was used to identify the two rock types (rock type I and II). Rock type I is for the high-porosity and high-permeability rock (sand), and type II is for the low-porosity and low-permeability rock (shale). Figure 6 shows the rock type distribution along the E-W cross-section.

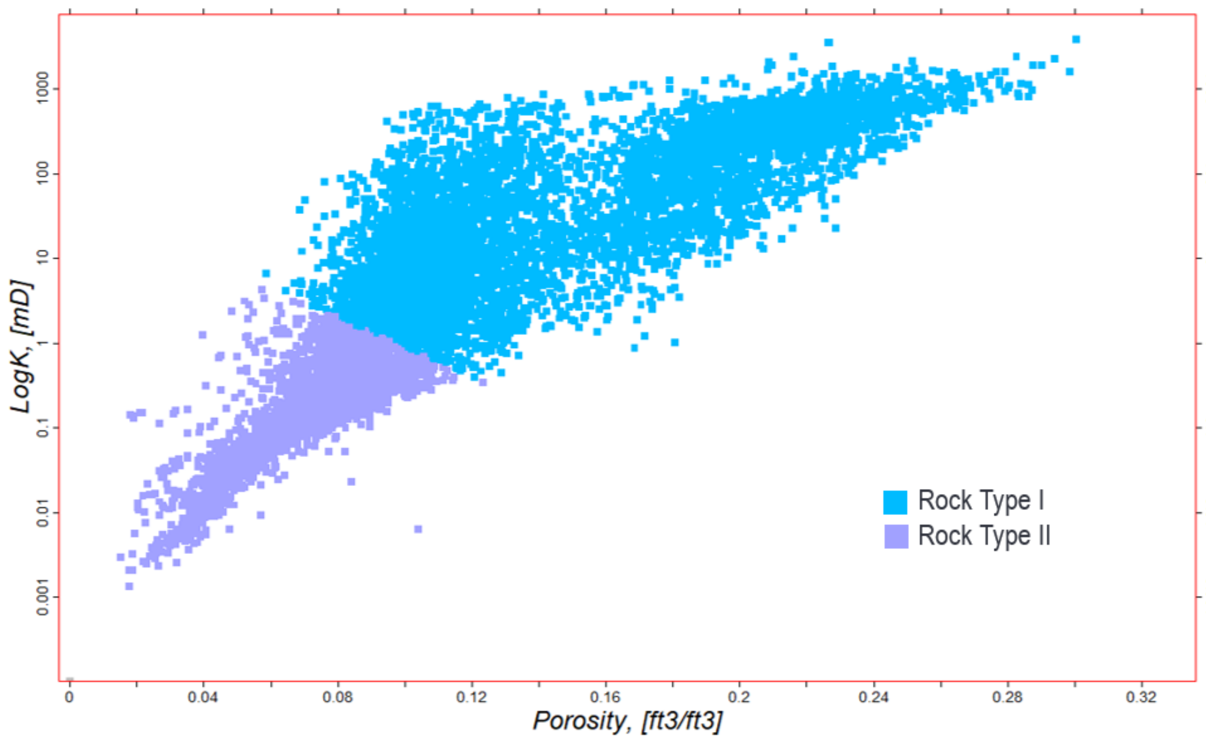

Figure 5. Rock types assigned according to porosity and log *k*.

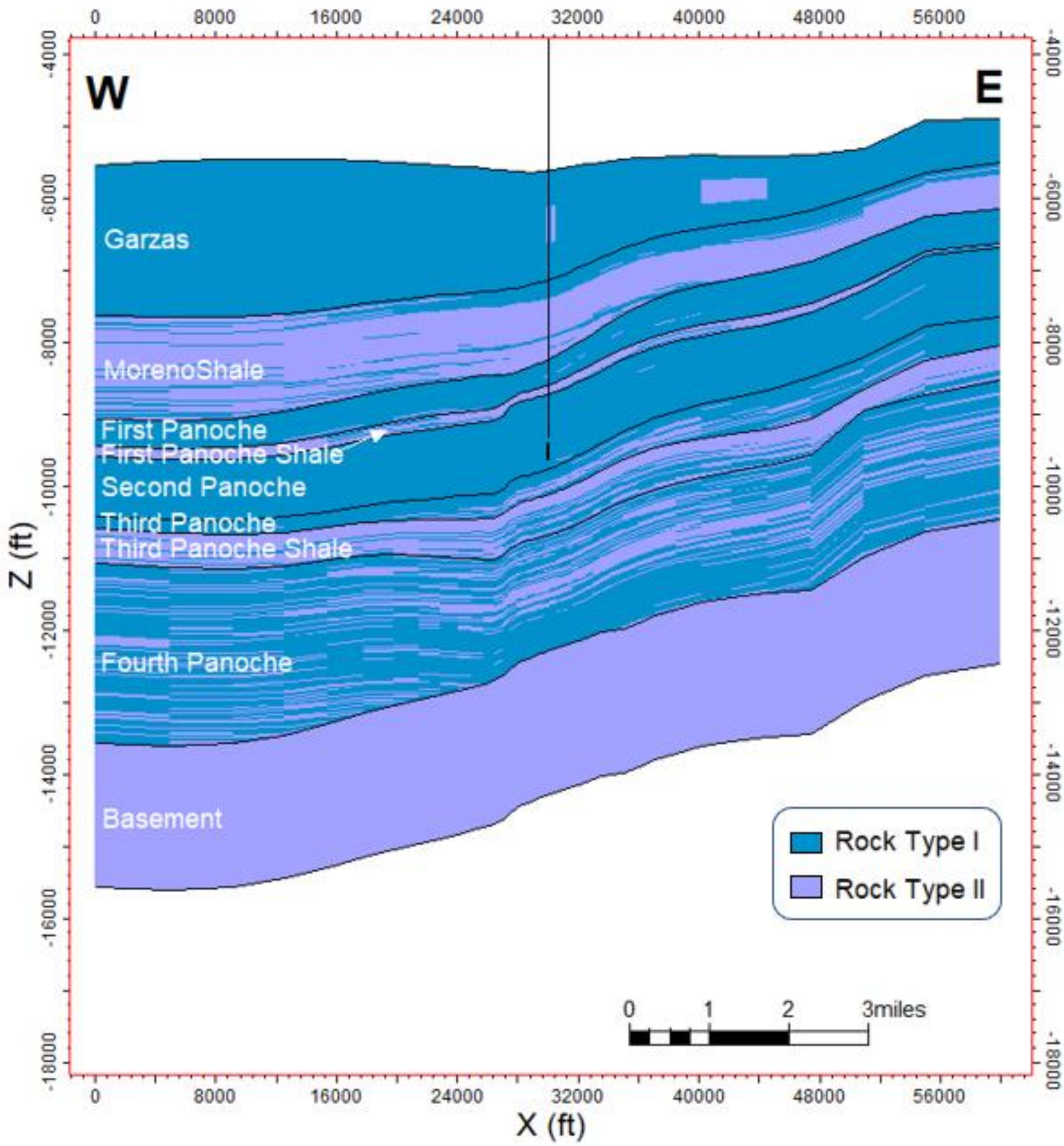

Figure 6. Rock types along the E-W cross-section. Vertical exaggeration is 5x.

Figure 7 shows the relative permeability with respect to brine saturation (S_w), for the CO_2-brine system during drainage and imbibition used for rock type I and II. The relative permeability of brine and CO_2 are represented by k_{rw} and k_{rg}, respectively. No special core analysis (SCAL) data were available in this preconstruction phase; therefore, irreducible water saturation (S_{wir}) was assumed to be 0.2 and 0.3 for sand and shale, respectively. Note that irreducible gas saturation (S_{gir}) was set to zero, which led to the simulated results being conservative in terms of CO_2 migration or plume-based AoR. SCAL with the rock cores in the Mendota storage site will be conducted from a proposed characterization well and used to define the relative permeability and capillary pressure to better estimate CO_2 plume behavior. Endpoint relative permeability at irreducible water saturation for both rock types was assumed to be 1.0. The Van Genuchten model was used to create the relative permeability and capillary pressure curve.

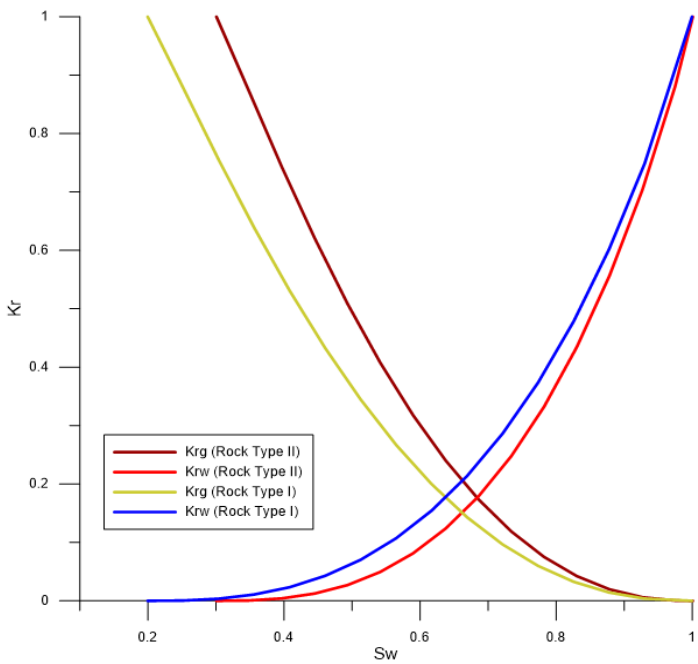

Figure 7. Relative permeability curves for rock type I and II.

Table 2 summarizes the constitutive relationships for the reservoir rock types in the model. No hysteresis in the relative permeability and capillary is considered currently.

Table 2. Constitutive relationships for rock types used in reservoir modeling.

Rock Type		Relative Permeability		Capillary Pressure (P_c)
		CO_2	**Brine**	
I	Drainage	van Genuchten model $S_e=(S_w–S_{wir})/(1–S_{wir})$ $k_{rg}=$ $k_{rg}(S_{wir})\ (1–S_e)^{1/2}\ (1–S_e^{1/m})^{2m}$ $m=0.92$	van Genuchten model $S_e=(S_w–S_{wir})/(1–S_{wir})$ $k_{rw}=$ $S_e^{\ 1/2}[1–(1–S_e^{1/m})^m]^2$ $m=0.92$	van Genuchten model $S_e=(S_w–S_{wir})/(1–S_{wir})$ $P_c=\alpha^{-1}[(S_e^{-1/m}-1]^{1/n}$ α=5.32E-5 $m=0.92$ $n=1/(1-m)$
	Imbibition (hysteresis)	No Hysteresis	No Hysteresis	No Hysteresis
II	Drainage	van Genuchten model $S_e=(S_w–S_{wir})/(1–S_{wir})$ $k_{rg}=$ $k_{rg}(S_{wir})\ (1–S_e)^{1/2}\ (1–S_e^{1/m})^{2m}$ $m=0.92$	van Genuchten model $S_e=(S_w–S_{wir})/(1–S_{wir})$ $k_{rw}=$ $S_e^{\ 1/2}[1–(1–S_e^{1/m})^m]^2$ $m=0.92$	van Genuchten model $P_c=\alpha^{-1}[(S_e^{-1/m}-1]^{1/n}$ α=1.19E-6 $m=0.92$ $n=1/(1–m)$
	Imbibition (hysteresis)	No Hysteresis	No Hysteresis	No Hysteresis

where
k_{rg} : CO_2 relative permeability
k_{rw} : aqueous relative permeability
S_w: water saturation
S_{wir}: irreducible water saturation
S_e: effective wetting fluid saturation
S_{co2}: CO_2 saturation ($=1–S_w$)
α^{-1} : entry pressure
n and m: fitting parameters

There is no direct measurement for rock compressibility available in this preconstruction phase. (Hall, 1953) reported the pore volume compressibility of different types of rocks where the sandstones with about 25% porosity are in the range of 3 to 4×10^{-6} psi^{-1}. These values are higher than the compiled data from Newman (1973), which showed a range of 1 to 3.5×10^{-6} psi^{-1} for the consolidated sandstone with porosity higher than 20%. For our simulation purpose, a value of 2×10^{-6} psi^{-1} was applied for the rock compressibility. This value is consistent with the core data from the consolidated sandstone (Newman, 1973). The actual rock compressibility can be measured in the laboratory using pore volume compressibility (PVC) experiments.

2.6 Boundary Conditions

No-flow boundary conditions were applied to the upper and lower boundaries of the model, with the assumption that the reservoir and the caprock are continuous through the region. A pore volume multiplier of 1×10^6 was applied to each cell in the horizontal boundaries of the ECLIPSE model to simulate an extensive reservoir (or infinite-acting boundary).

2.7 Initial Conditions

Initial reservoir pressure, temperature, and salinity data were collected from the nearby oil and gas fields (<20 mile), reported in (DOGGR, 1998). A pressure gradient of 0.4339 psi/ft was estimated from Figure 8, which is slightly greater than the hydrostatic condition. The reservoir temperature with respect to depth is shown in Figure 9. The geothermal gradient of 0.0146°F/ft was found with the surface temperature of 51.8°F. These pressure and geothermal gradients were used to assign the initial conditions for the reservoir simulation, which are given in Table 3.

Unlike the reservoir pressure and temperature, salinity data exhibit no specific trend in Figure 10. The low salinity value (5,900 ppm) at a depth of 9,300 ft is from Cantua Creek oil field, which is about 20 miles south of Mendota site. The sample was taken from the Gatchell sand, which is Eocene and younger than the Moreno. Note that in the plot there is only one salinity measurement (20,000 ppm) available from the Panoche sand at Gill Ranch, which is the closest field from the Mendota. Since the salinity tends to increase to the west (away from recharge area), the TDS at Panoche sand in the Mendota site is expected to meet the minimum requirement (>10,000 ppm). Thus, uniform salinity of 25,000 ppm was used for the initial condition in the reservoir simulation. Fluid sampling and testing, including in-situ, will be conducted at a proposed characterization well, and the initial conditions will be updated accordingly.

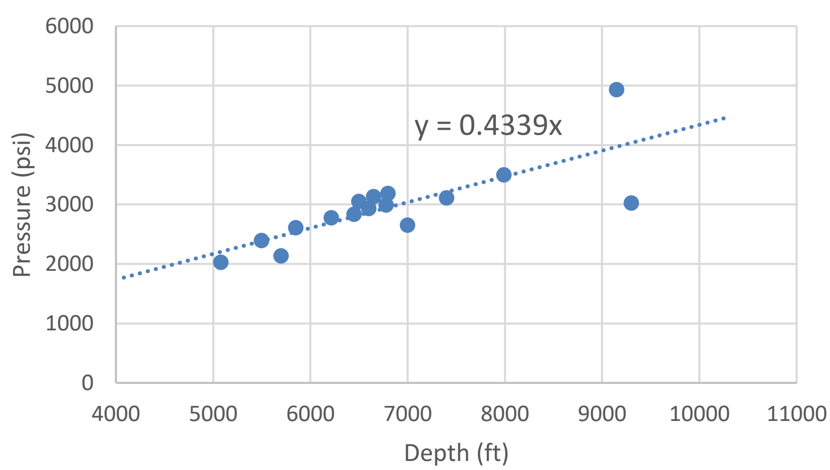

Figure 8. Initial reservoir pressure in oil and gas reservoirs near the Mendota site.

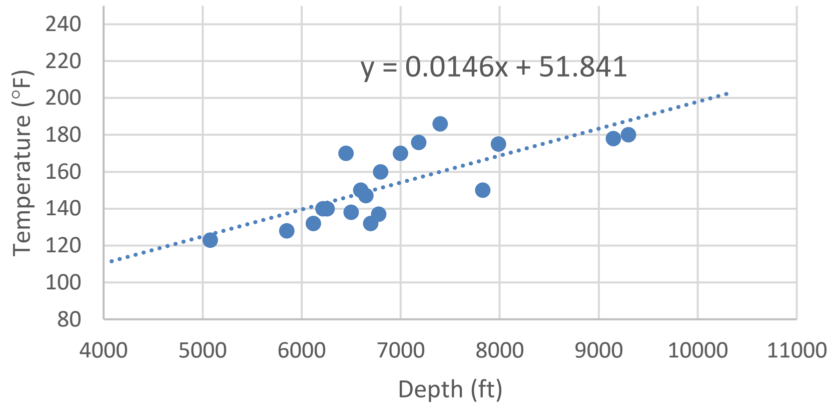

Figure 9. Initial reservoir temperature in oil and gas reservoirs near the Mendota site.

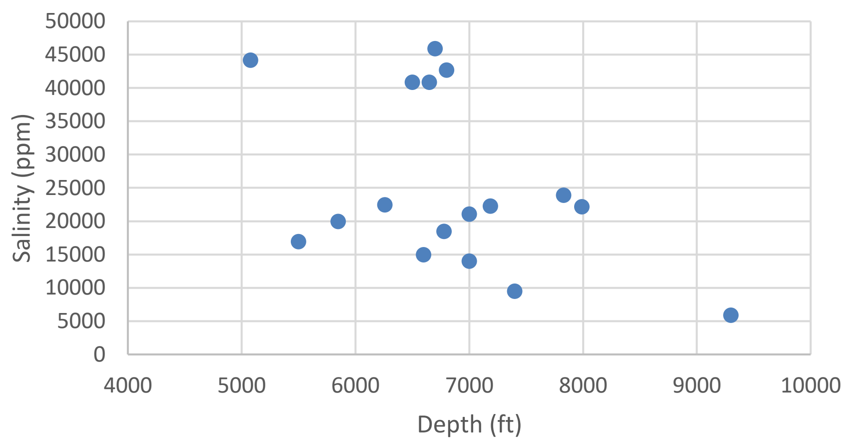

Figure 10. Initial salinity in oil and gas reservoirs near the Mendota site.

Table 3. Initial reservoir conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	137.5 249.7	°F	–6350 –13350	DOGGR (1998)
Formation pressure	4211	psi	–9505	DOGGR (1998)
Fluid density	N/A	lbm/ft^3		61.06~63.04 lbm/ft^3 assigned from the ECLISPE simulator according to temperature and pressure
Salinity	25000	ppm	Uniform in the model	DOGGR (1998)

2.8 Operational Information

Details of the injection operation are presented in Table 4.

Table 4. Operating details for Mendota_INJ_1.

Operating Information	**Injection Well 1**
Location (global coordinates) X (Latitude) Y (Longitude)	 36.75585015 –120.36440423
Model coordinates (ft) X Y	 1600305.8 520689.2
No. of perforated intervals	1
Perforated interval (ft MSL) Z top Z bottom	 –9,400 –9,620
Wellbore diameter (in)	9.625 in
Planned injection period (20 years) Start End	 To be determined To be determined
Injection duration (years)	20
Injection rate (tonnes/day)	958

2.9 Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 5. There is no site-specific data for the fracture pressure or fracture gradient in the injection and confining zones. However, Shryock and Slagle (1968) has indicated that the fracture gradient can vary from 0.6 to 1.0 psi/ft due to the structural stresses and formation elasticity. Fracture gradient is closely related to formation breakdown. Limiting injection pressure below fracture gradient will prevent the initiation/propagation of vertical and horizontal fracture. The DOGGR report, *Evaluation and Surveillance of Injection Projects* (DOGGR, 1984), contains the average breakdown gradient data for oil fields located in Central and Southern California. The listed breakdown gradients were compiled by Shryock and Slagle (1968) from the squeeze-cementing operations at various depths. The breakdown gradient is 0.63 to 0.64 psi/ft at 5,000 to 8,000 ft depth in the San Joaquin Valley basin. This number is somewhat lower than the state's Class II UIC program document, which indicated a historical fracture gradient of 0.7 psi/ft for the Coalinga District (Walker, 2011). A higher fracture gradient of 0.96 psi/ft in the San Joaquin basin was observed from a step rate test (Mathis, Brierley, Sickles, Nelson, & Thorness, 2000). To be conservative in terms of fracture pressure, 0.65 psi/ft was assumed for the fracture gradient in the model, and 90% of the fracture pressure was used as a constraint for the reservoir simulation.

The fracture pressure for the injection and confining zones can be estimated from a formation stress test using the MDT* modular formation testing tool. The pressure will be slowly raised until the rock breaks, providing a direct measurement of the fracture pressure of the formation. The pressure is then allowed to bleed off to show the closure pressure. The fracture pressure from these measurements will be used to guide the maximum injection pressure to prevent the initiation/propagation of vertical and horizontal fractures. The fracture pressure and closure pressure will also be used to evaluate the in-situ stress (Zoback, et al., 2003) for geomechanics evaluation.

Table 5. Injection pressure details for Mendota_INJ_1.

Injection Pressure Details	**Injection Well 1**
Fracture gradient (psi/ft)	0.65
Maximum injection pressure (90% of fracture pressure) (psi)	5,677.4
Elevation corresponding to maximum injection pressure (ft MSL)	–9,505
Elevation at the top of the perforated interval (ft MSL)	–9,400
Calculated maximum injection pressure at the top of the perforated interval (psi)	5,616

3. Computational Modeling Results

3.1 Predictions of System Behavior

Figure 11 presents the AoR after 20 years of injection based on the dynamic modeling results (the maximum extent of the plume and pressure front), along with wells identified within the AoR. The surface area of the pressure-based AoR is 2.2 square miles. The predicted evolution of the plume and pressure front is shown in the *Testing and Monitoring Plan* (Schlumberger, 2021c) and the *Post -Injection Site Care (PISC) and Site Closure Plan* (Schlumberger, 2021e).

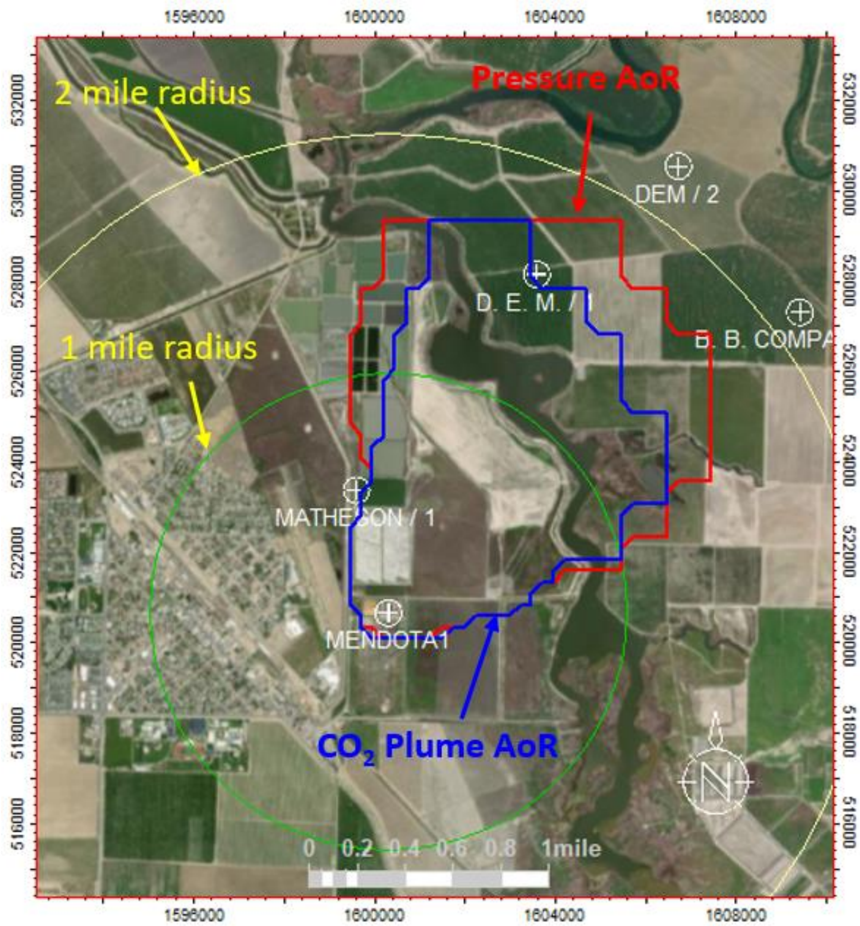

Figure 11. Map of the AoR as delineated by the reservoir model simulation.

3.2 Model Calibration and Validation

Currently, there are no data available for model calibration or history-matching. Uncertain parameters and their degree of uncertainty/variation for the sensitivity analysis will be evaluated and determined after site-specific data are collected. If statistical variation from the samples cannot be determined, minimum and maximum values will be selected according to the possible ranges/uncertainties based on expert opinion. The pre-injection testing program proposed in *Construction Details* (Schlumberger, 2021g) will be used for model calibration prior to injection. One-variable-at-a-time sensitivity analysis will be followed to evaluate the uncertainty in the model parameters. For the injection and post-injection period, iterative model updates will be based on the *Testing and Monitoring Plan* (Schlumberger, 2021c) and the *Post-Injection Site Care (PISC) and Site Closure Plan* (Schlumberger, 2021e).

4. AoR Delineation

AoR is defined as the area where a geological CO_2 storage project may cause endangerment to an underground source of drinking water (USDW). The predicted AoRs (CO_2 plume and pressure-based) are delineated based on the reservoir modeling. The pressure front is delineated by using the minimum or critical pressure (ΔPc) necessary to reverse flow direction between the lowermost USDW and the injection zone therefore causing fluid flow from the injection zone into the formation matrix of the USDW. The method in the EPA (2018) guidance was used to calculate ΔPc.

Since there are no site-specific fluid pressure and density measurements available and the estimated initial reservoir pressure is close to hydrostatic conditions, the method developed and published by Nicot et al. (2008) and Bandilla et al. (2012) was used. The critical pressure is calculated by

$$\Delta P_c = \frac{1}{2} \cdot g \cdot \xi \cdot (z_u - z_i)^2 \quad (2)$$

where

g = acceleration due to gravity

z_u = elevation of the lowermost USDW

z_i = elevation of the injection zone

ξ = linear density gradient (coefficient) defined as

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i},$$

and where
ρ_i = fluid density of the injection zone and
ρ_u = fluid density of the lowermost USDW

This method estimates a pressure differential that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and is based on two assumptions:

1. Hydrostatic conditions
2. Initially linearly varying densities in the borehole and constant density once the injection zone fluid is lifted to the top of the borehole

Using this method, the pressure differential was calculated based on an injection depth of 9,705 ft below KB and the lowermost USDW depth of approximately 1,615 ft below KB. The results yield an estimate of approximately 3.5 psi (0.241 bar).

In addition to the pressure-based AoR, CO_2 plume-based AoR is defined as the CO_2 plume front with the gas saturation greater than or equal to 0.02 (2%). The predicted AoR will encompass the larger extent of either plume-based or pressure-based AoR results.

5. Corrective Action

5.1 Tabulation of Wells within the AoR

A fixed radius of 2.5 miles around the proposed Mendota_INJ_1 well was used to include all wells in the pre-construction model's AoR. The 2.5-mile radius was preferred to tabulate corrective action wells over the simulated plume AoR to account for uncertainties in AoR geometry. A total of 84 wells were found in the California Department of Water Resources Water Data Library and the IHS Enerdeq databases (California Department of Water Resources, 2021; IHS, 2020).

5.1.1 Wells within the AoR

The majority of the wells within the 2.5-mile radius of the proposed Mendota_INJ_1, 79 of the 84, were drilled for water resources (Figure 12) (California Department of Water Resources, 2021). The depths of the water wells in the 2.5-mile radius range from 20 to 550 ft, and the wells are used as irrigation and monitoring wells. Sixty of the water wells within the 2.5-mile radius of Mendota_INJ_1 do not have a depth record; however, as they were drilled for water resource purposes, they are not believed to be deeper than the USDW and would not be a conduit risk to deeper formations. More information on the water wells can be found in the *Class VI Permit Application Narrative* (Schlumberger, 2021i).

The CalGEM (2020) database lists five wells within a 2.5-mile radius of the proposed injection well (Figure 13 and Table 6). All five of the wells were deemed dry holes and plugged and abandoned directly after drilled. Three of these wells, Matheson 1, DEM 1, and DEM 2 were targeting formations above the Moreno shale seal (Figure 14) (CalGEM, 2020). Two wells, Amstar 1 and B.B. Co. 1 penetrate the Moreno shale into the Panoche sands (Figure 15) (CalGEM, 2020). No wells have been identified in the AoR through the Moreno shale prior to or after the database records were accessed.

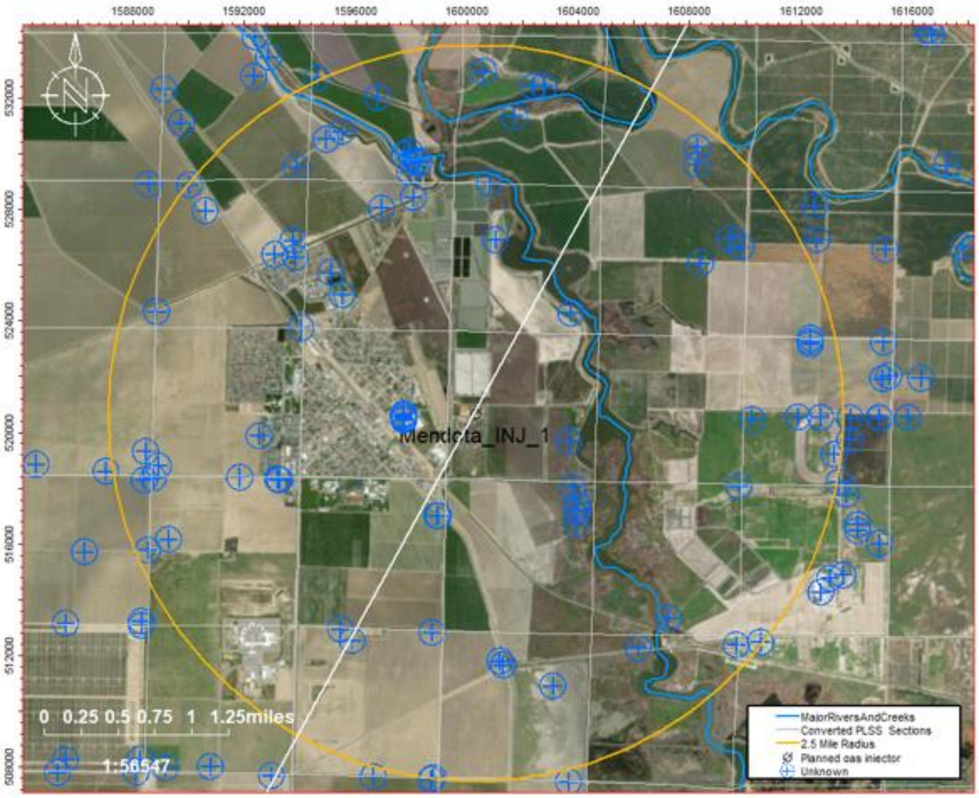

Figure 12. Water wells within a 2.5-mile radius of the proposed Mendota_INJ_1.

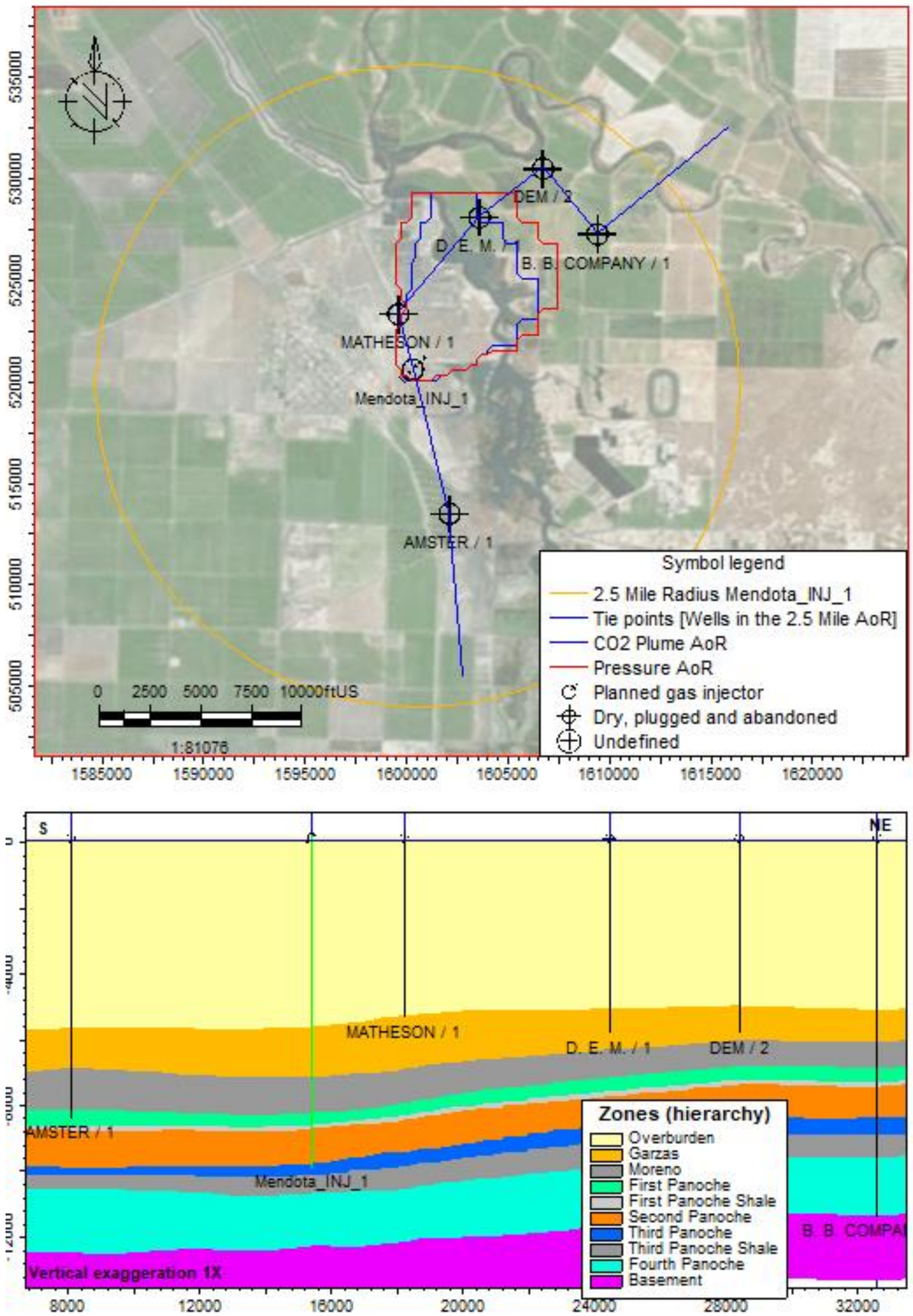

Figure 13. Mendota site location map showing CO_2 and pressure AoRs along with nearby oil and gas wells within a 2.5-mile radius of the proposed Mendota_INJ_1. Bottom figure shows blue intersection plane view and landing depths of nearby oil and gas wells.

Table 6. Oil and gas wells within a 2.5-mile radius of the proposed Mendota_INJ_1.

API	Lease Name	Well #	Status	Well Type	Operator Name	Spud Date	PA Date	Distance (miles)
0401922584	Amstar	1	Plugged	DH[a]	Gamma Corp.	06/15/1987	6/27/1987	1.48
0401920752	B.B. Co.	1	Plugged	DH	Atlantic Richfield Co.	04/12/1973	5/5/1973	2.32
0401906007	Matheson	1	Plugged	DH	Donco Co.	05/13/1958	5/24/1958	0.51
0401921173	DEM	1	Plugged	DH	D. J. Pickrell, Operator	11/10/1978	11/18/1978	1.65
0401921281	DEM	2	Plugged	DH	D. J. Pickrell, Operator	09/06/1979	9/11/1979	2.36

[a] DH, dry hole

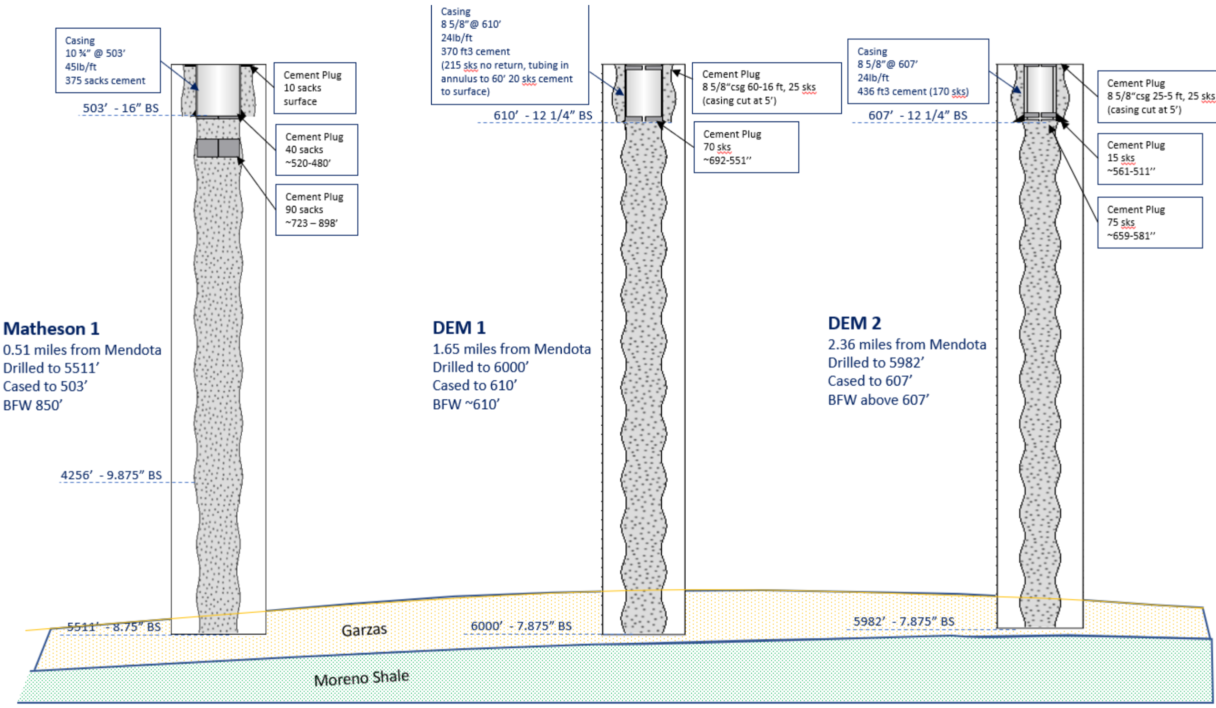

Figure 14. Plugged and abandoned wells above the confining zone (Moreno shale) (CalGEM, 2020).

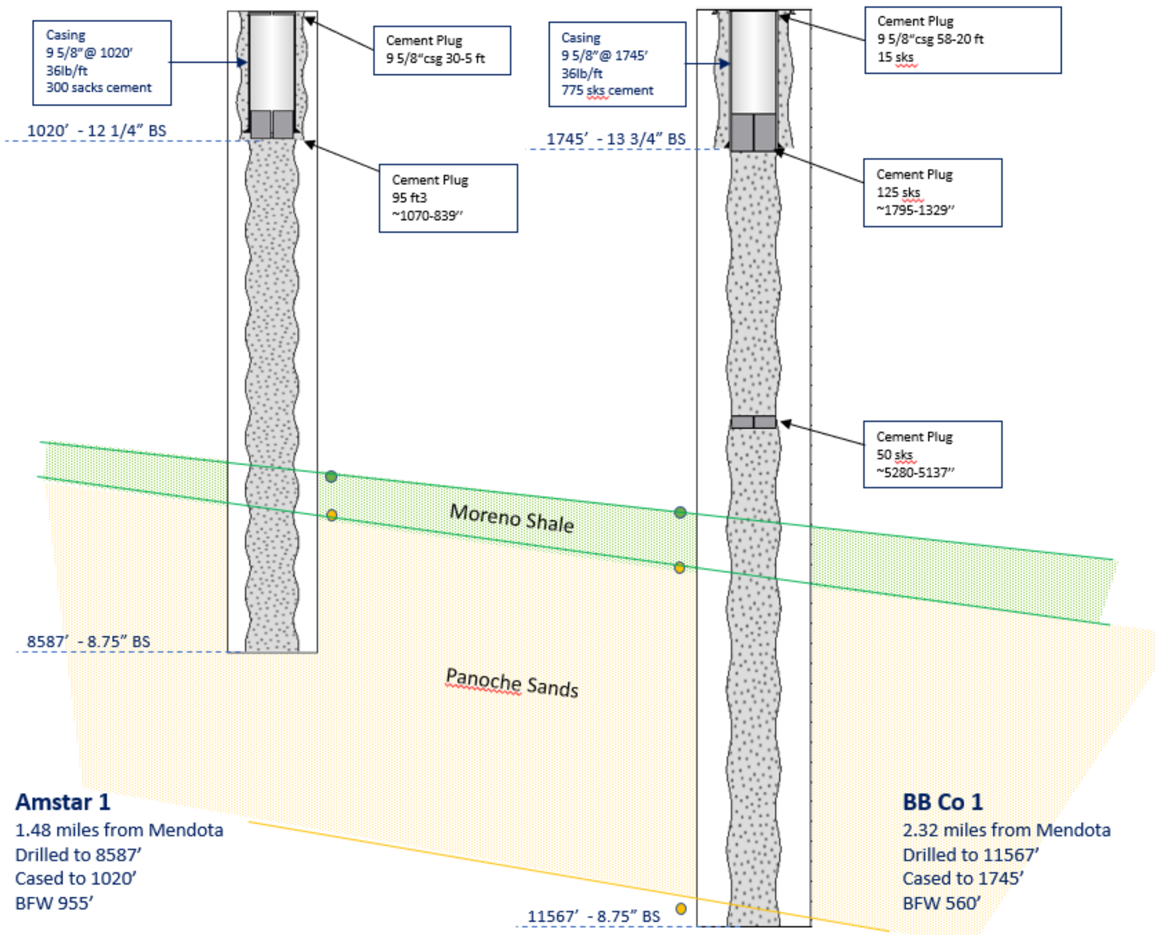

Figure 15. Completion details for oil and gas wells penetrating the confining zone within a 2.5-mile radius of the proposed Mendota_INJ_1 (CalGEM, 2020).

Of the five wells in the California Geologic Energy Management Division (CalGEM, 2020) database described above, two wells within the 2.5-mile radius of the proposed injection well penetrate the Moreno shale, Amstar 1 and BB Co 1. Amstar 1 was drilled into the First Panoche sandstone to a depth of 8,587 ft, and BB Co 1 was drilled to the basement rock to a depth of 11,567 ft. The CalGEM database datasheets have the drilling and abandonment records and image files for the wireline evaluation logs. Both wells have surface casing cemented below the base of fresh water and are openhole plugged and abandoned. BB Co 1 has surface casing below the estimated USDW; however, Amstar 1 surface casing is shallower than the USDW. In the current abandonment configuration, they do not provide a seal from Panoche sand injection to the formations above the Moreno and may require corrective action. Amstar 1 does not penetrate the primary confining zone (First Panoche shale) and is 1.5 miles south (downdip, opposite direction of plume migration) from the proposed injection site. BB Co 1 is 2.32 miles from the proposed injection site and outside of the modeled AoR. Final remediation plans for these wells will be informed by updated plume simulations after site-specific data are acquired. A potential re-abandonment plan for both wells is following in the Corrective Action Schedule.

5.1.2 Plan for Site Access

Property and well ownership rights are currently being determined. Access to these sites will be determined before the characterization well is drilled in the pre-operational phase of the project.

5.1.3 Corrective Action Schedule

As described in section 5.1.1, the Amstar 1 and BB Co 1 wells do not provide a seal from Panoche sand injection to the formations above the Moreno and may require corrective action. Amstar 1 is less than 1.5 miles from the proposed injection site and may require remedial work prior to CO_2 injection operations. BB Co 1 is 2.32 miles from the proposed injection site and outside of the modeled AoR however is in the same direction of plume migration so may require future remediation. Figure 16 and Figure 17 show wells before and after plug and abandonment workover.

The Matheson 1, DEM 1, and DEM 2 were targeting formations above the Moreno shale seal. TD for DEM 1 and DEM 2 is at the top of Moreno shale, but the wells do not penetrate the shale. As such, no remedial abandonment is deemed necessary at this time.

The procedures described below are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect USDWs; any significant modifications due to unforeseen circumstances will be described in the plugging report. Completed plugging forms, associated charts, and all laboratory information will be provided to the regulatory agency as required by permit. The plugging report shall be certified as accurate by CES and plugging contractor and shall be submitted within 60 days after plugging is completed.

5.1.3.1 *Amstar 1 – Procedures for Remedial Plug and Abandonment*

Depth reference is from GL and depth is MD unless otherwise noted.

- Prepare location by removing all relevant landscaping/lighting fixtures as well as surface piping and electrical components as needed.
- Move in workover rig and rig up.
- Install blowout preventer equipment and test to rated pressure.
- Move in workover rig and rig up. Notify by phone California Department of Conservation a minimum of 24 hours prior to moving in rig.
- Pickup workstring with 8.5-in drill bit and drill out existing surface cement plug and bottom-most plug at casing shoe (~830 ft–1070 ft). Continue drilling to ~8,587 ft.
- Pull out of hole, remove drill bit, and run in hole to 8,587 ft. Raise tubing 5 ft to place cement.
- Rig up cement crew to well.
- Pump 10-bbl fresh water and then mix and pump 65-bbl CO_2-resistant cement with .5% dispersant. Mix at 15.8 ppg and yield 1.08 ft^3/sk. Displace cement to spot as balanced plug of length ~900 ft. Estimated top of cement plug is 7687 ft.
- Trip out of the hole 100 ft above the plug and circulate well to clean cement from tubing.
- Wait 8 hours. Trip in and tag top of plug with ~ 10,000 lb to make sure plug is set.
- Pull back 10 ft and close in annulus and pressure well 500 psi above normal surface pressure.
- Close tubing and monitor pressure in tubing and tubular annulus. Record pressures every 5 minutes.
- Pressure should be maintained ±5% for 30 minutes. If not, there may need to be a waiting period before testing the cement again 4 hours later.

It is anticipated that at least eight additional plugs of length ~900 ft will be necessary. The above procedure shall be repeated to build the stack of cement plugs covering the interval 8587 ft–850 ft, which will also cover the USDW. To build each successive plug, tubing shall be placed ~5 ft above the previous plug.

To build the surface cement plug

- Trip out of hole laying down workstring to ±120 ft. Pump 10-bbl fresh water and then mix and pump 8-bbl Class G cement with .5% dispersant. Mix at 15.8 ppg and yield 1.08 ft^3/sk. Displace cement to spot as balanced plug. Estimated top of cement 5 ft from GL.
- Cut off casing strings and casing heads and wellhead. Cut flush with current grade. Final grade -1 ft below GL needs to be visible.
- Top off 9 5/8-in. casing with sacked cement, if necessary.
- Weld plate over top of well. Plate needs to be visible.
- Rig down workover rig and move out.

Refer to Figure 16 for schematics of the Amstar 1 wellbore before and after the P&A operation.

5.1.3.2 BB Co 1 – Procedures for Remedial Plug and Abandonment

Depth reference is from GL and depth is MD unless otherwise noted.

- Prepare location by removing all relevant landscaping/lighting fixtures as well as surface piping and electrical components as needed.
- Move in workover rig and rig up.
- Install blowout preventer equipment and test to rated pressure.
- Move in workover rig and rig up. Notify by phone California Department of Conservation a minimum of 24 hours prior to moving in rig.
- Pickup workstring with 8.5-in drill bit and drill out existing surface cement plug and bottom-most plug at casing shoe (~1,329 ft–1,795 ft). Continue drilling to ~11,567 ft.
- Pull out of hole, remove drill bit and run in hole to 11,567 ft. Raise tubing 5 ft to place cement.
- Rig cementers to well.
- Pump 10-bbl fresh water and then mix and pump 65-bbl CO_2-resistant cement with .5% dispersant. Mix at 15.8 ppg and yield 1.08 cu ft/sk. Displace cement to spot as balanced plug of length ~900 ft. Estimated top of cement plug is 10,667 ft.
- Trip out of the hole 100 ft above the plug and circulate well to clean cement from tubing.
- Wait 8 hours. Trip in and tag top of plug with ~ 10,000 lb to make sure plug is set.
- Pull back 10 ft and close in annulus and pressure well 500 psi above normal surface pressure.
- Close tubing and monitor pressure in tubing and tubular annulus. Record pressures every 5 minutes.
- Pressure should be maintained ±5% for 30 minutes. If not, there may need to be a waiting period before testing the cement again 4 hours later.

It is anticipated that at least 10 additional plugs of length ~900 ft each will be necessary. The above procedure shall be repeated to build the stack of cement plugs covering the interval 11,567 ft–1,595 ft. To build each successive plug, tubing shall be placed ~5 ft above previous plug.

To build the USDW and surface cement plugs

- Trip out of hole laying down workstring to ±1,200 ft. Pump 10-bbl fresh water and then mix and pump 38-bbl Class G cement with .5% dispersant. Mix at 15.8 ppg and yield 1.08 ft^3/sk. Displace cement to spot as balanced plug. Estimated top of cement for the USDW cement plug is 700 ft.
- Trip out of the hole 100 ft above the plug and circulate well to clean cement from tubing.
- Wait 8 hours. Trip in and tag top of plug.
- Pull back 10 ft and close in annulus and pressure well 500 psi above normal surface pressure.
- Close tubing and monitor pressure in tubing and tubular annulus. Record pressures every 5 minutes.
- Pressure should be maintained ±5% for 30 minutes. If not, there may need to be a waiting period before testing the cement again 4 hours later.

- Trip out of hole laying down workstring to ±110 ft. Pump 10-bbl fresh water and then mix and pump 8-bbl Class G cement with .5% dispersant. Mix at 15.8 ppg and yield 1.08 ft^3/sk. Displace cement to spot as balanced plug. Estimated top of cement 5 ft from GL.
- Cut off casing strings and casing heads and wellhead. Cut flush with current grade. Final grade -1 ft below GL needs to be visible.
- Top off 9 5/8-in. casing with sacked cement, if necessary.
- Weld plate over top of well. Plate needs to be visible.
- Rig down workover rig and move out.

Refer to Figure 17 for schematics of the BB Co 1 wellbore before and after the P&A operation.

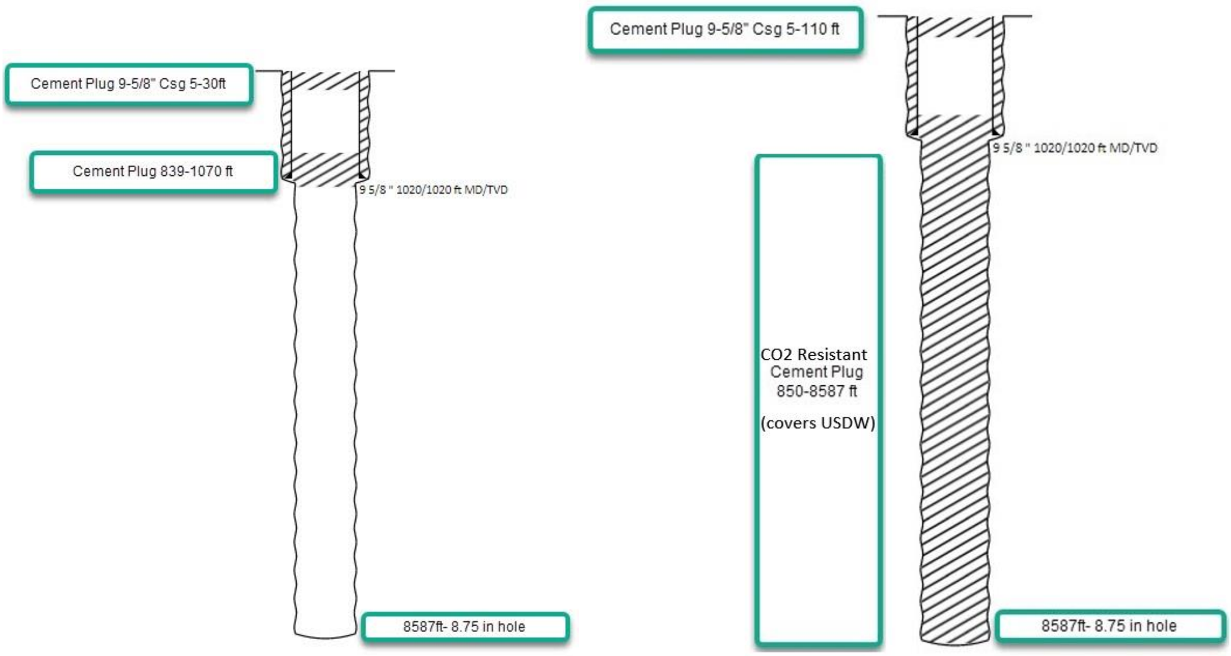

Figure 16. Amstar 1 wellbore before (left) and after (right) P&A operation.

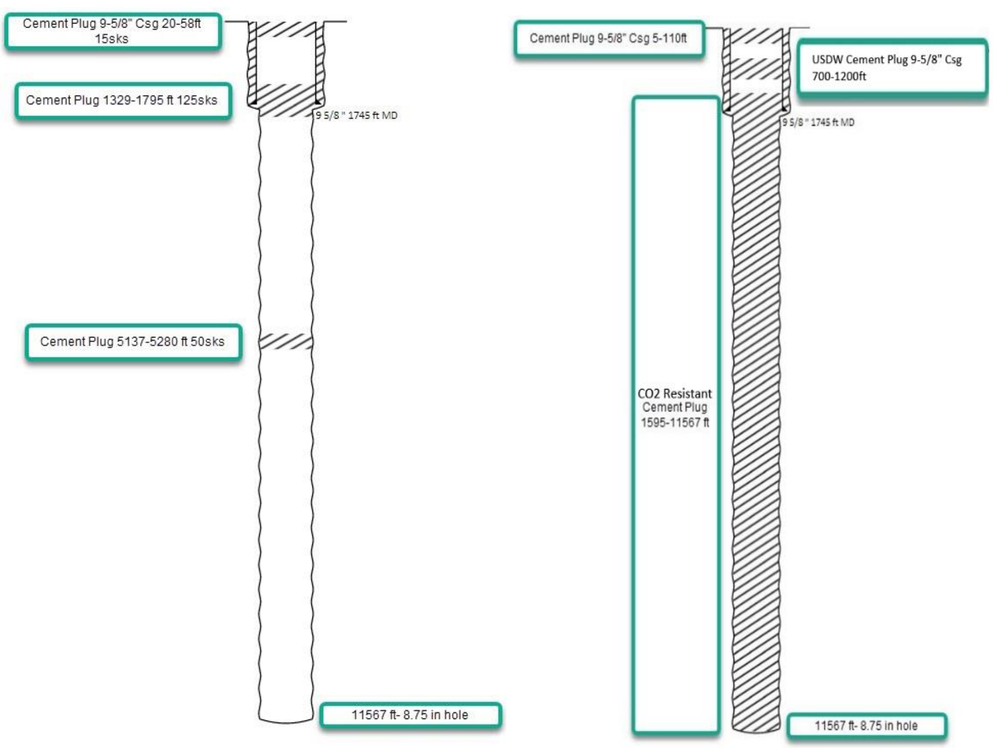

Figure 17. BB Co 1 wellbore before (left) and after (right) P&A operation.

6. Reevaluation Schedule and Criteria

6.1 AoR Reevaluation Cycle

Clean Energy Systems will take the following steps to evaluate project data and, if necessary, reevaluate the AoR. AoR reevaluations will be performed during the injection and post-injection phases. The methods for delineating the AoR will be consistent throughout the life of the project. Clean Energy Systems will

- Review available monitoring data and compare it to the model predictions. Clean Energy Systems will analyze monitoring and operational data from the injection well (Mendota_INJ_1), the monitoring and geophysical wells, other surrounding wells, and other sources to assess whether the predicted CO_2 plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan (Schlumberger, 2021c) and the PISC and Closure Plan (Schlumberger, 2021e). Specific steps of this review include the following:

    - Reviewing available data on the position of the CO_2 plume and pressure front (including pressure and temperature monitoring data and pulsed neutron saturation and seismic survey data). Specific activities will include the following:

        - Correlating data from time-lapse pulsed neutron logs, time-lapse vertical seismic profile (VSP) surveys, and other seismic methods (e.g., 3D surveys) to locate and track the movement of the CO_2 plume. A good correlation between the data sets will provide strong evidence in validating the model's ability to represent the storage system. Also, 2D and 3D seismic surveys may be employed to determine the plume location as described in the Testing and Monitoring Plan (Schlumberger, 2021c) and the PISC and Site Closure Plan (Schlumberger, 2021e) (as applicable).

        - Reviewing downhole reservoir pressure data collected from various locations and intervals using a combination of surface and downhole pressure gauges.

        - Reviewing analysis of fluid samples from Mendota_OBS_1.

    - Reviewing ground water chemistry monitoring data taken in the shallow monitoring wells, the deeper USDW monitoring well (Mendota_USDW_1) and the above confining zone monitoring well (Mendota_ACZ_1) to verify that there is no evidence of excursion of CO_2 or brines that represent an endangerment to any USDWs.

    - Reviewing operating data, e.g., on injection rates and pressures, and verifying that it is consistent with the inputs used in the most recent modeling effort.

    - Reviewing any geologic data acquired since the last modeling effort, e.g., additional site characterization performed, updates of petrophysical properties from core analysis, etc. Identifying whether any new data materially differ from modeling inputs/assumptions.

- Compare the results of computational modeling used for AoR delineation to monitor data collected. Monitoring data will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. Pressure responses at the injection well and monitoring wells will be used primarily for model calibration (or history matching). In addition, the simulated plume distribution will be compared to the observed plume by use of VSP and/or 3D seismic data. The CO_2 breakthrough curve at the Mendota_OBS_1 will also be reviewed for model calibration. Clean Energy Systems will demonstrate this degree of accuracy by comparing monitoring data against the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site.

- If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of plume and pressure front movement, Clean Energy Systems will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AoR is needed. The report will include the data and results demonstrating that no changes are necessary.

- If material changes have occurred (e.g., in the behavior of the plume and pressure front, operations, or site conditions) such that the actual plume or pressure front may extend beyond the modeled plume and pressure front, Clean Energy Systems will re-delineate the AoR. The following steps will be taken:

    - Revising the site conceptual model based on new site characterization, operational, or monitoring data

    - Calibrating the model to minimize the differences between monitoring data and model simulations

    - Performing the AoR delineation as described in the Computational Modeling and Corrective Action sections of this report (sections 2 and 0, respectively).

    - Review wells in any newly identified areas of the AoR and apply corrective action to deficient wells. Specific steps include

        - Identifying any new wells within the AoR that penetrate the confining zone and provide a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion

        - Determining which abandoned wells in the newly delineated AoR have been plugged in a manner that prevents the movement of CO_2 or other fluids that may endanger USDWs

    - Perform corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with CO_2.

- Prepare a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA within 1 year of the reevaluation. The report will include maps that highlight similarities and differences in comparison with previous AoR delineations.

- Update the AoR and Corrective Action Plan to reflect the revised AoR, along with other related project plans, as needed.

Clean Energy Systems will reevaluate the above described AoR every 5 years during the injection and post-injection phases.

In addition, monitoring and operational data will be reviewed periodically (likely annually) by Clean Energy Systems during the injection and post-injection phases. Clean Energy Systems will collect and review data more regularly during the first 12 months of the injection phase. Specifically, pressure and seismic results will be reviewed on a monthly basis to identify any deviations from expected conditions. The reservoir flow model will be history matched against the observed parameters measured at the monitoring wells. Pressure will be monitored as described in the Testing and Monitoring Plan (Schlumberger, 2021c). The time-lapse pressure monitoring data will be compared to the model-predicted time-lapse pressure profiles. Clean Energy Systems will provide a brief report of this review to the UIC Program Director and discuss the findings.

If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume and/or pressure front is occurring or there are deviations from modeled predictions such that the actual plume or pressure front may extend vertically or horizontally beyond the modeled plume and pressure front, Clean Energy Systems will initiate an AoR reevaluation prior to the next scheduled reevaluation. Such deviations may be evidenced by the results of direct or indirect monitoring activities including mechanical integrity test (MIT) failures or loss of mechanical integrity; observed pressure and saturation profiles; changes in the physical or chemical characteristics of the CO_2; any detection of CO_2 above the confining zone (e.g., based on hydrochemical/physical parameters); microseismic data indicating slippage in or near the confining zone or microseismic data within the injection zone that indicates slippage and propagation into the confining zone; or arrival of the CO_2 plume and/or pressure front at certain monitoring locations that diverges from expectations, as described below.

6.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled reevaluation of the AoR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, pulsed neutron saturation, and the deep ground water (> 5,800 ft below KB) constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes include:

- ***Pressure:*** Changes in pressure that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.

- ***Temperature:*** Changes in temperature that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.

- ***Pulsed neutron saturation:*** Increases in CO_2 saturation that indicate the movement of CO_2 into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- ***Deep ground water constituent concentrations:*** Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brines into or above the confining zone will trigger a new evaluation of the AoR unless the changes are found to be related to the well integrity. (Any well integrity issues will be investigated and addressed.)

- ***Exceeding fracture pressure conditions:*** Pressure in any of the injection or monitoring wells exceeding 90% of the geologic formation fracture pressure at the point of measurement. This would be a violation of the permit conditions. The Testing and Monitoring Plan (Schlumberger, 2021c) and the operating procedures in the Summary of Requirements (Schlumberger, 2021a) provide discussions of pressure monitoring and specific procedures that will be completed during the injection startup period.

- ***Exceeding established baseline hydrochemical/physical parameter patterns:*** A statistically significant difference between observed and baseline hydrochemical/physical parameter patterns (e.g., fluid conductivity, pressure, temperature) immediately above the confining zone. The Testing and Monitoring Plan (Schlumberger, 2021c) provides extended information regarding how pressure, temperature, and fluid conductivity will be monitored.

- ***Compromise in injection well mechanical integrity:*** A significant change in pressure within the protective annular pressurization system surrounding each injection well that indicates a loss of mechanical integrity at an injection well.

- ***Seismic monitoring identification of subsurface structural features:*** Seismic monitoring data that indicate the presence of a fault or fracture in or near the confining zone or a fault or fracture within the injection zone that indicates propagation into the confining zone. The Testing and Monitoring Plan (Schlumberger, 2021c) provides extended information about the microseismic monitoring network.

An unscheduled AoR reevaluation may also be needed if it is likely that the actual plume or pressure front may be significantly different from the modeled plume and pressure front because any of the following has occurred:

- Seismic event greater than M3.5 within 8 miles of the injection well

- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected)

- If new site characterization data change the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AoR.

- If the arrival time of the plume and/or pressure front at Mendota_OBS_1 and/or when pressure and plume data recorded at Mendota_OBS_1 differs significantly from modeled projections.

- Initiation of competing Panoche formation injection projects within the same injection formation within a 1-mile radius of the injection well.

- Significant land use changes that would affect site access.

Clean Energy Systems will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. The exact timing of an AoR reevaluation will vary depending on the triggering events above; however, a 1-month timeframe is likely. CES will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required.

If an unscheduled reevaluation is triggered, Clean Energy Systems will perform the steps described at the beginning of this section of this plan.

7. References

Bandilla, K., Kraemer, S., & Birkholzer, J. (2012). Using semi-analytic solutions to approximate the area of potential impact for carbon dioxide injection. *International Journal of Greenhouse Gas Control, 8*, 196-204. doi:https://doi.org/10.1016/j.ijggc.2012.02.009

CalGEM. (2020). *Well Finder*. Retrieved from https://maps.conservation.ca.gov/doggr/wellfinder/#/

California Department of Water Resources. (2021). *Water Data Library (WDL) Station Map*. Retrieved from https://wdl.water.ca.gov/waterdatalibrary/Map.aspx

DOGGR. (1984). *Evaluation and Surveillance of Water Injection Projects.* Report M13.

DOGGR. (1998). *California Oil and Gas Fields, Volume 1.* Sacramento, California: California Department of Conservation, Division of Oil and Geothermal Resources.

DOGGR. (2019). *https://www.conservation.ca.gov/dog*. Retrieved from Division of Oil, Gas, and Geothermal Resources.

EPA. (2018). *UIC Program Class VI Well Area of Review and Corrective Action Guidance.*

Fenghour, A., Wakeham, W., & and Vesovic, V. (1998). The Viscosity of Carbon Dioxide. *Journal of Physical and Chemical Reference Data, 27*, 31-44. doi:https://doi.org/10.1063/1.556013

Hall, H. (1953). Compressibility of reservoir rocks. *Journal of Petroleum Technology*, 17-19.

IHS. (2020). Retrieved from https://my.ihs.com/energy

Mathis, S., Brierley, G., Sickles, K., Nelson, D., & Thorness, R. (2000). Water-fracs provide cost-effective well stimulation alternative in San Joaquin Valley wells. *SPE/AAPG Western Regional Meeting*. doi:https://doi.org/10.2118/62521-MS

Newman, G. (1973). Pore-volume compressibility of consolidated, friable, and unconsolidated reservoir rocks under hydrostatic loading. *Journal of Petroleum Technology, 25*, 129-134. doi:https://doi.org/10.2118/3835-pa

Nicot, J., Oldenburg, C., Bryant, S., & Hovorka, S. (2008). Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces. *Energy Procedia, 1*, 47-54. doi:https://doi.org/10.1016/j.egypro.2009.01.009

Redlich-Kwong. (1949). *Redlich-Kwong equation of state.*

Schlumberger. (2021a). *Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions.*

Schlumberger. (2021b). *Attachment B: Area of Review and Corrective Action Plan 40 CFR 146.84(b) Clean Energy Systems Mendota.*

Schlumberger. (2021c). *Attachment C: Testing and Monitoring Plan 40 CFR 146.90 Clean Energy Systems Mendota.*

Schlumberger. (2021d). *Attachment D: Injection Well Plugging Plan 40 CFR 146.92(B) Clean Energy Systems Mendota.*

Schlumberger. (2021e). *Attachment E: Post-Injection Site Care and Site Closure Plan 40 CFR 146.93(A) Clean Energy Systems Mendota.*

Schlumberger. (2021f). *Attachment F: Emergency and Remedial Response Plan 40 CFR 146.94(A) Clean energy Systems Mendota.*

Schlumberger. (2021g). *Attachment G: Construction Details Clean Energy Systems Mendota.*

Schlumberger. (2021h). *Attachment H: Financial Assurance Demonstration 40 CFR 146.85 Clean Energy Systems Mendota.*

Schlumberger. (2021i). *Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota.*

Schlumberger. (2021i). *Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota.*

Schlumberger. (2021j). *Quality Assurance and Surveillance Plan.*

Shryock, S., & Slagle, K. A. (1968). Problems related to squeeze cementing. *Journal of Petroleum Technology, 20*(8), 801-807. doi:https://doi.org/10.2118/1993-PA

Spycher, N., & Pruess, K. (2005). CO2-H2O mixtures in the geological sequestration of CO2.II. Partitioning in chloride brines at 12-100 C and up to 600 bar. *Geochimica et Cosmochimica Acta, 69*, 3309-3320. doi:https://doi.org/10.1016/j.gca.2005.01.015

Walker, J. (2011). *California Class II UIC Program Review.* Report submitted to Ground Water Office USEPA Region IX.

Zaytsev, I., & Aseyev, G. (1993). *Properties of Aqueous Solutions of Electrolytes.* Boca Raton, Florida, USA: CRC Press.

Zoback, M. D., Barton, C. A., Brudy, M., Castillo, D. A., Finkbeiner, T., Grollimund, B. R., . . . Wiprut, D. (2003). Determination of stress orientation and magnitude in deep wells. *International Journal of Rock Mechanics and Mining Sciences, 40*(7-8), 1049-1076. doi:https://doi.org/10.1016/j.ijrmms.2003.07.001