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

Facility Information

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3.0 AoR and Corrective Action Plan

3.1 Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) and 3-D seismic data for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. 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 CO_2 and water phases
- Liquid and gas relative permeability
- Capillary pressure data
- Proposed injection well completions and injection rates over the life of the project

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 of the CTV III storage project, the AoR encompasses the maximum aerial extent of the critical pressure front that was calculated as being necessary to move brine from the injection zone to the USDW via an open conduit.

3.1.1 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) and multi-phase fluids as well as 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 and the solubility of CO_2 in water is modeled by Henry's Law. The Peng-Robinson Equation of State establishes the properties of CO_2 over the Pressures and temperatures of the model. 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 extent of the CO_2 plume and the pressure changes in the reservoir during and after injection which are used 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.

3.1.2 Site Geology and Hydrology

The Project area is a northwest-dipping homocline located 7 miles northwest of the Union Island Gas field in the southern Sacramento Basin of California. The Mokelumne River Formation reservoir sands are composed of a series of fluvial-deltaic sequences that were sourced by the Sierra Nevada terrain to the east and prograded west-southwestward into the forearc basin. Local erosion by the downcutting Meganos submarine canyon has resulted in reduced thickness of the Mokelumne River Formation along the north and western portions of the AoR; however, the reservoir sands are present across the entire AoR (Figure 3.1, cross-section A-A'). One normal fault, the Midland fault, and two reverse faults, the West Tracy and Stockton Arch faults, offset the Mokelumne River Formation. These faults are sealing in nature and form the western, southern, and a portion of the eastern boundaries of the AoR.

The Mokelumne River Formation sands are bound above by the regional Capay Shale, and below by the H&T Shale. The Capay Shale spans the entire Sacramento Basin and serves as a regional seal that was deposited during a major transgressive event in the Eocene. The Capay Shale has an average gross thickness of ~200 feet in the greater Project area and has 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 Mokelumne River Formation in adjacent gas fields (e.g., Rio Vista Gas field, McDonald Island Gas field).

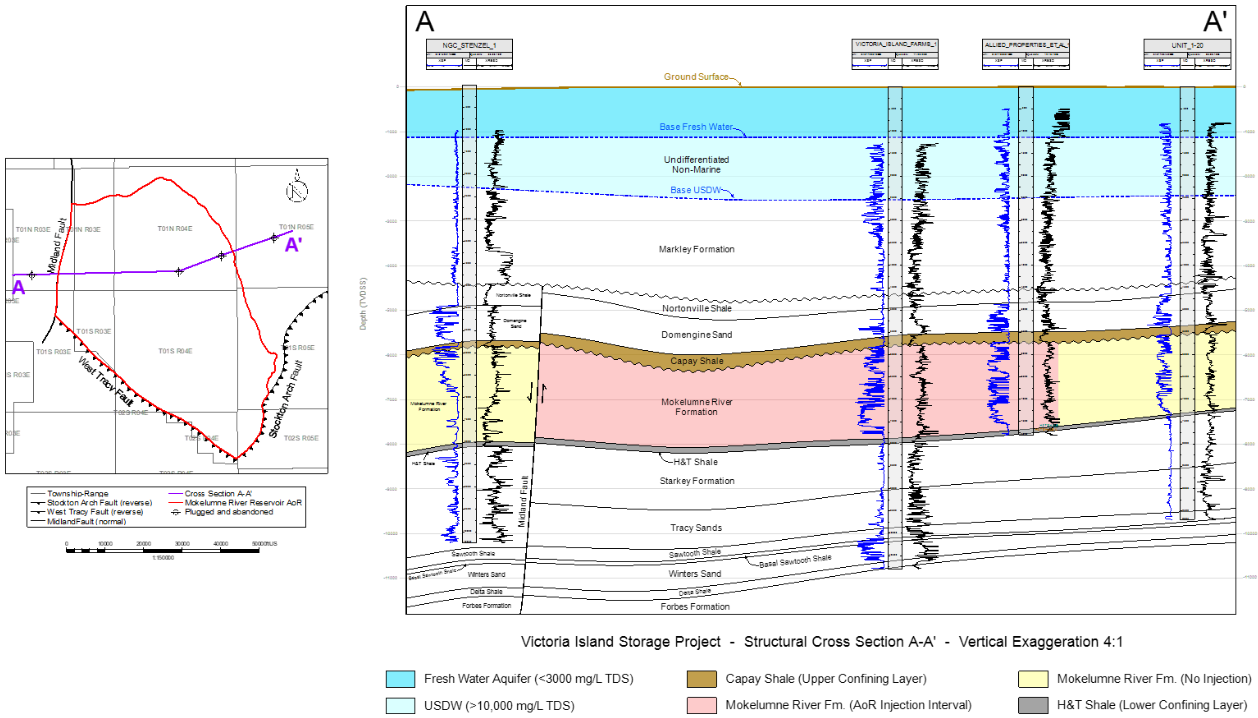


Figure 3.1: Cross section showing stratigraphy and lateral continuity of major formations across the AoR.

The Class VI injection wells will target injection in the Mokelumne River Formation sands. No gas has been produced from these sands within the AoR. However, the Mokelumne River Formation is a gas-bearing reservoir at nearby fields such as Rio Vista, King Island, McDonald Island, the abandoned Bixler Gas field and the Roberts Island Gas field. Well data, open-hole well logs and core (Figure 3.2), define the subsurface geological characteristics of stratigraphy, lithology and rock properties.

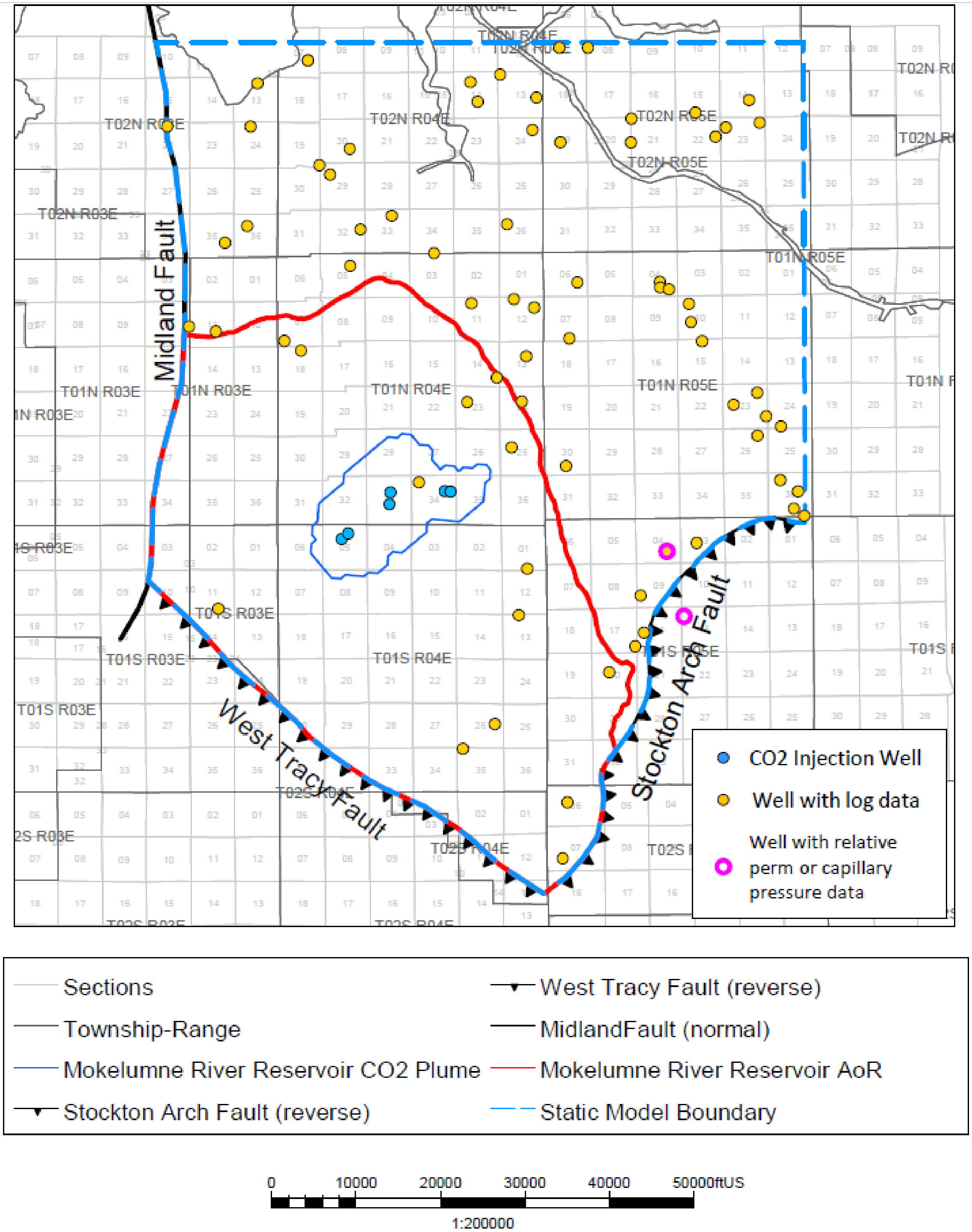


Figure 3.2: Location of wells with open-hole log data and Winters zone relative permeability or capillary pressure data used to develop the static and computational models.

3.1.3 Model Domain

A static geological model developed with Schlumberger's 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 3.1**.

Table 3.1. Model domain information.

Coordinate System	State Plane		
HorizontalDatum	North American Datum (NAD) 27		
Coordinate System Units	Feet		
Zone	Zone 2		
FIPSZONE	0402	**ADSZONE**	3301
Coordinate of X min	2,104,802.28	**Coordinate of X max**	2,181,962.01
Coordinate of Y min	35,524.40	**Coordinate of Y max**	135,851.00
Elevation of bottom of domain	-8,485.82	**Elevation of top of domain**	-4,534.97

A tartan grid with varying cell XY dimensions was rotated to an orientation of 40 degrees over the model domain, as shown in **Figure 3.3**. The 40-degree rotation is aligned with the structural and depositional trends of the Mokelumne River Formation and is parallel to the direction of fluid flow which allows for faster computation times. In the CO_2 plume area, the grid cells are predominantly 500'x500' but some cells are as small as 50'x50' in the region immediately around the planned injectors. The grid cell size increases with greater distance away from the main injection area, where cells up to 1000'x1000' cover the areas of the model that are furthest from the injectors.

As illustrated in **Figure 3.3**, the western and southern boundaries of the model are defined by the Midland, West Tracy, and Stockton Arch faults. The significance of these geologic boundaries to the computational modeling will be discussed later in this document.

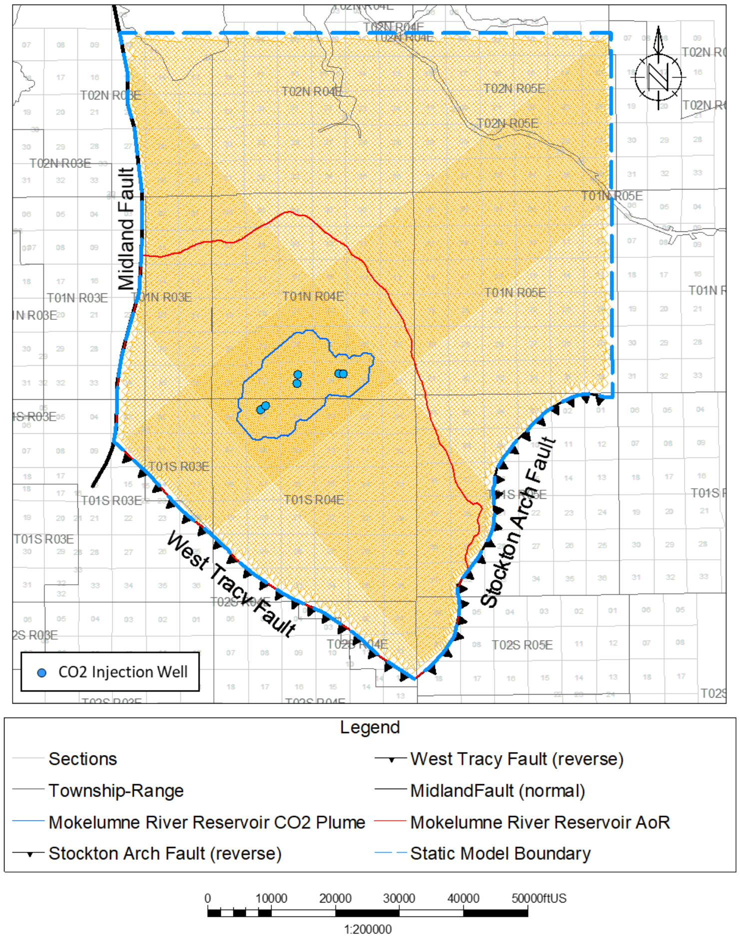


Figure 3.3: Plan view of the model boundary and geo-cellular grid used to define the CO_2 plume extent and associated AoR.

The open-hole logs have a half-foot resolution and a constant vertical cell height of 20 feet was utilized over the model domain to generate grid layers as shown in **Figure 3.4**. The 20-foot cell height provides the vertical resolution necessary to capture significant lithologic heterogeneity (sand versus shale) which helps to ensure accurate upscaling of log data and distribution of reservoir properties in the static model. **Figure 3.5** shows a comparison of open-hole log data and the associated upscaled logs for a well within the AoR.

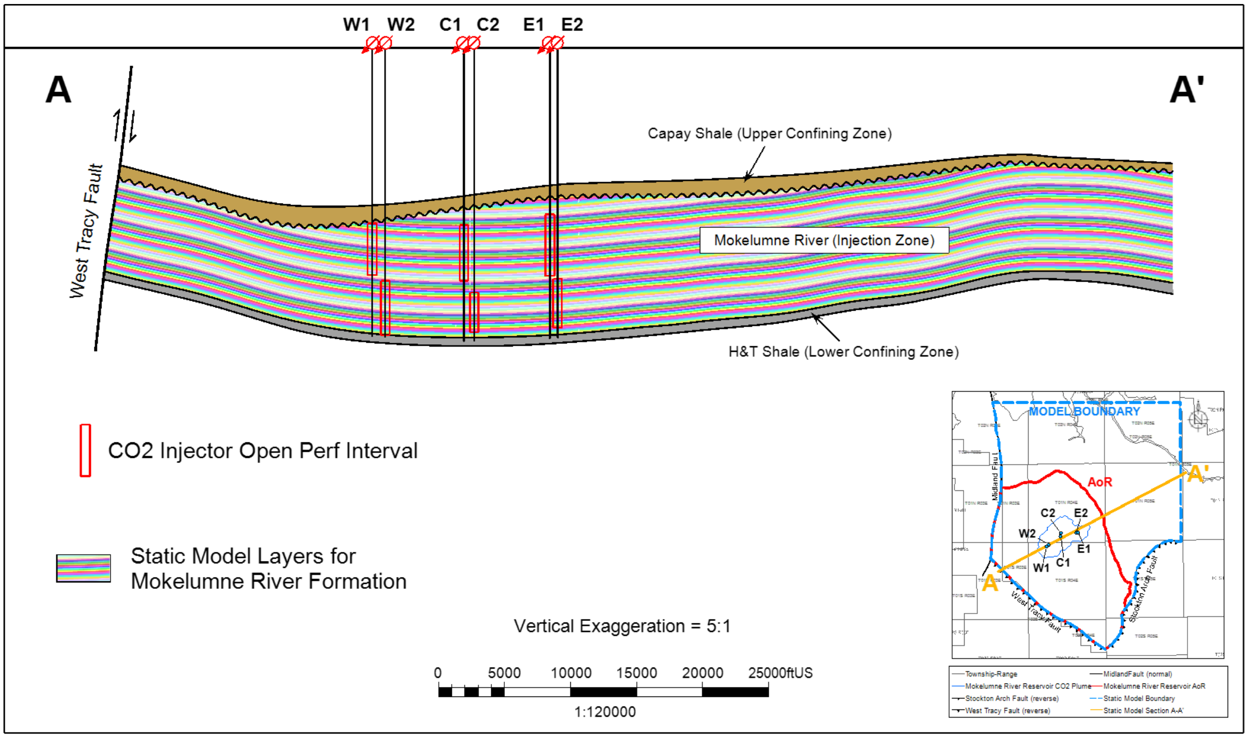


Figure 3.2: Static model grid layering of the Mokelumne River Formation. Stratigraphic units are bound to the west, southwest, and southeast by the Midland, West Tracy, and Stockton Arch faults, respectively.

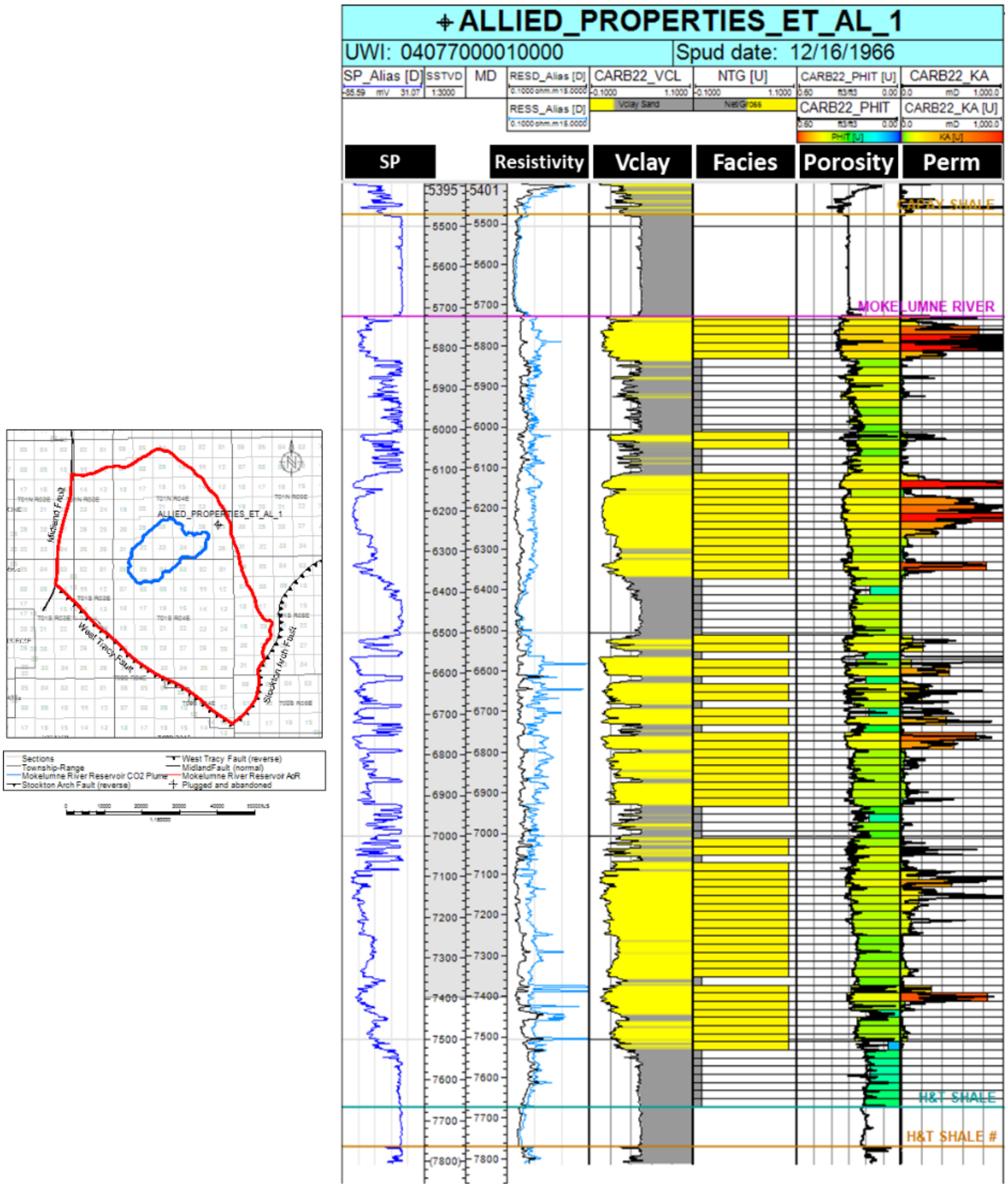


Figure 3.5: Well "Allied Properties Et Al 1" upscaled logs versus open-hole logs.

3.1.4 Porosity and Permeability

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

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (**Figure 3.6**). The transform from core data is illustrated in **Figure 3.7**.

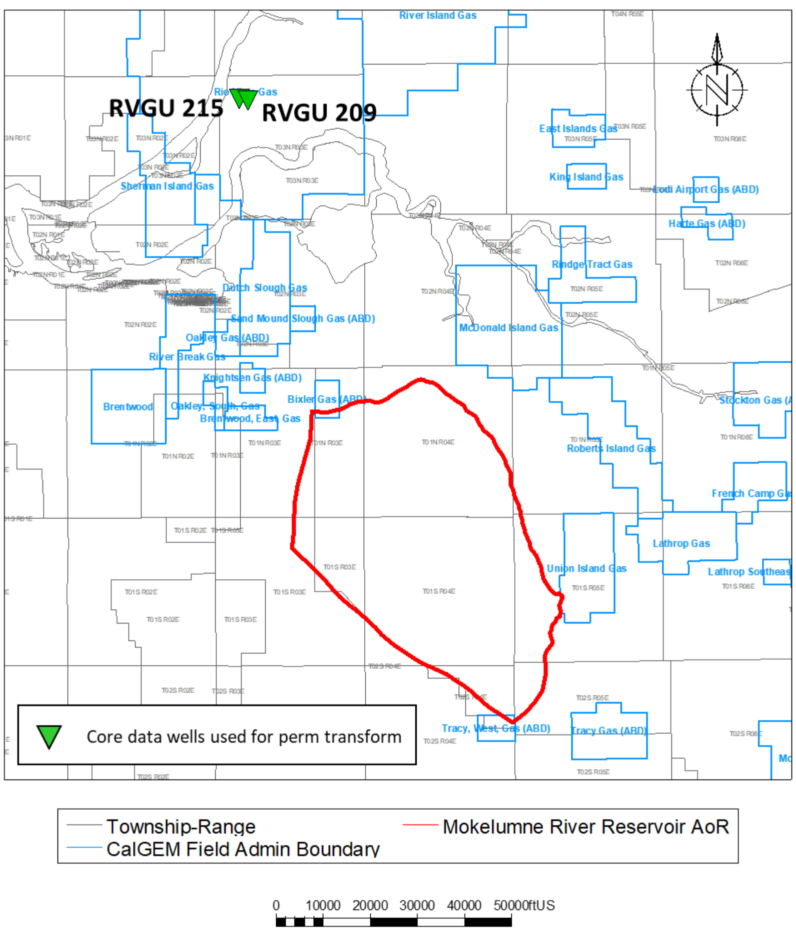


Figure 3.6. Location of wells with core data used for permeability transform.

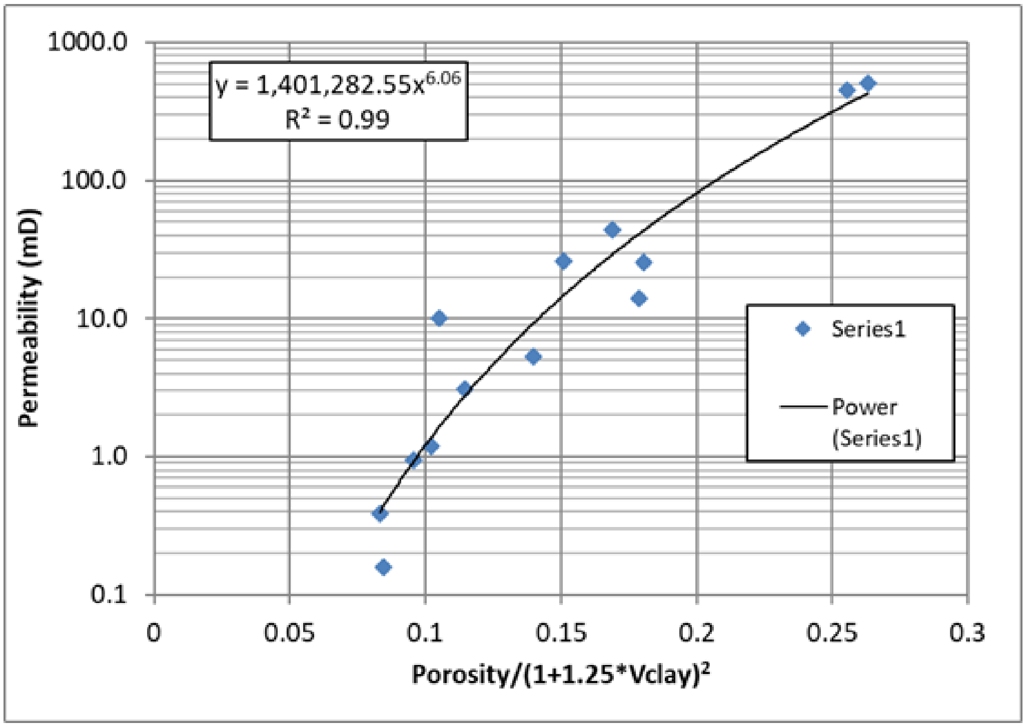


Figure 3.7. Permeability transform for Sacramento Basin zones

Figure 3.8 shows porosity and permeability histograms for the Mokelumne River Formation sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. **Figure 3.8** shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model.

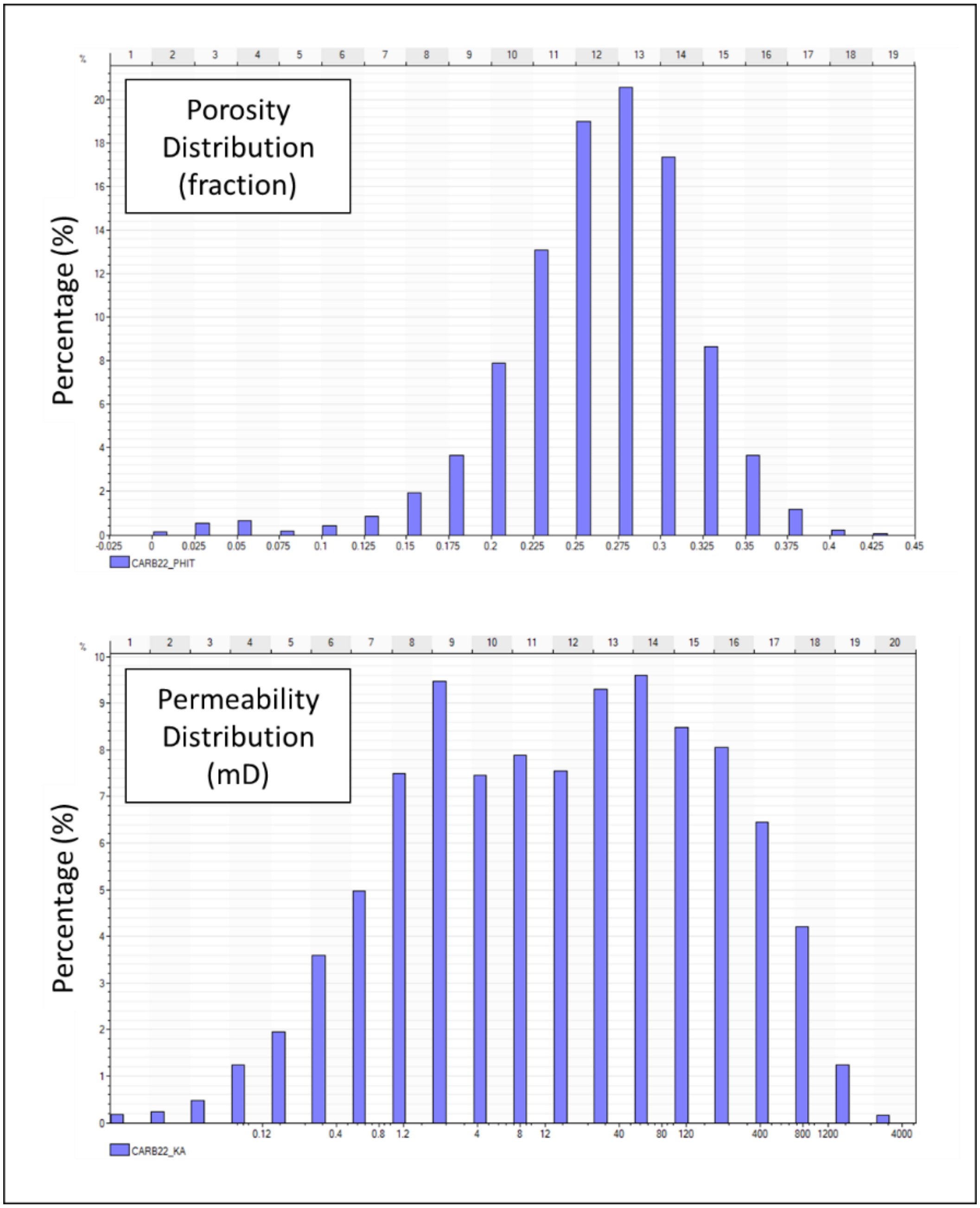


Figure 3.8. Mokelumne River Formation porosity and permeability distribution in the static model.

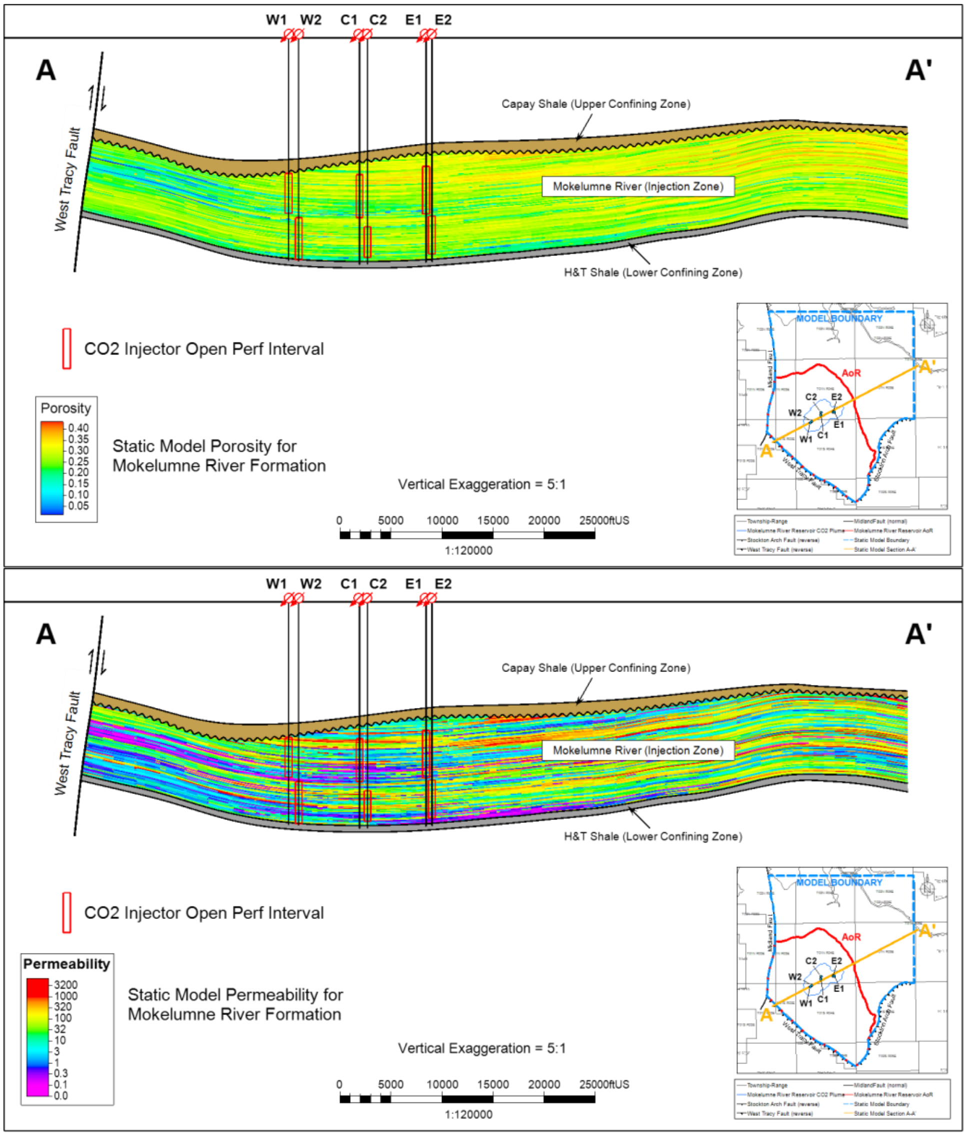


Figure 3.9. Sections through the static grid showing the distribution of porosity and permeability in the reservoir.

3.1.5 Constitutive Relationships and Other Rock Properties

As no site specific Mokelumne River Formation relative permeability or capillary pressure data was available, data obtained from cores (**Figure 3.2**) from the similar geologic age and setting Winters formation in the neighboring Union Island Gas field were used for the computational simulation. The simulation and AoR will be updated once site specific core data is obtained during the pre-operational testing phase.

Figure 3.10 and 3.11 shows the relative permeability curve and capillary pressure curve used in the computational modeling.

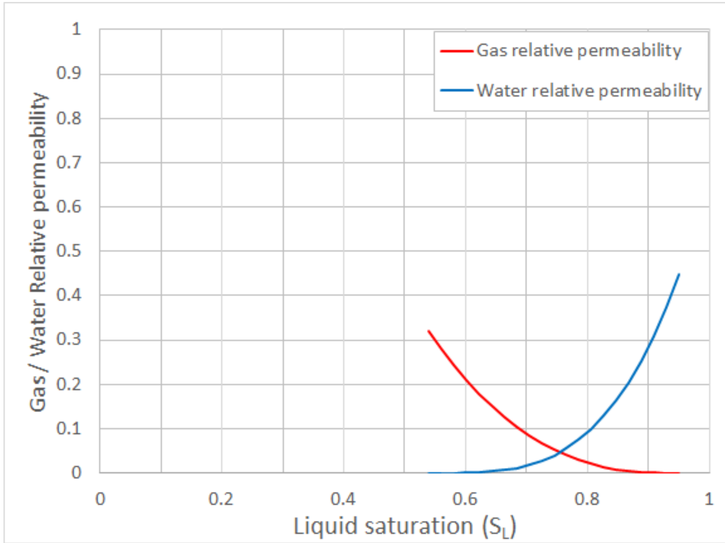


Figure 3.10. Relative permeability curves for Gas-Water system

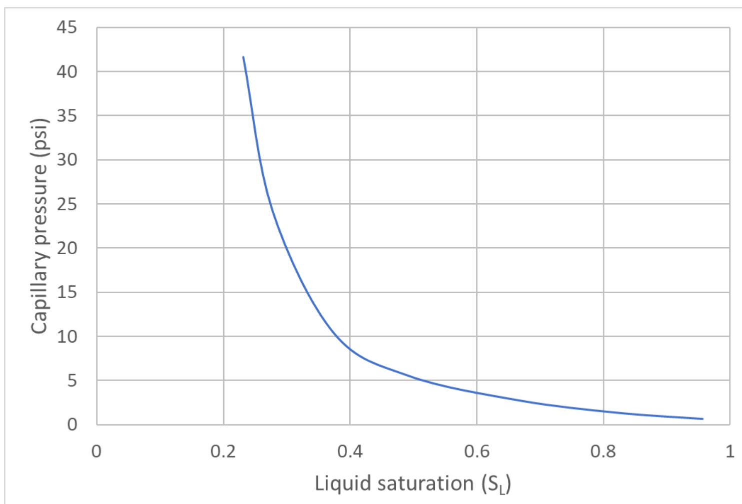


Figure 3.11. Capillary pressure curve

3.1.6 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.

Due to the low salinity expected for the Mokelumne River Formation, the stable mineralogy of the formation, minor expected effect on the AoR and for computational efficiency, reactive transport was not included as a part of the compositional simulation modeling done for the project at this time.

3.1.7 Boundary Conditions

The following Boundary conditions were applied to the model domain:

The overlying Capay shale which is continuous and present at thickness >100' over the model domain has low permeability, has been shown to be a proven hydrocarbon seal over the model domain and was thus set as a no flow boundary.

The Western, Southern and part of the Eastern edge of the model domain, defined by the Midland, West Tracy and Stockton Arch faults were set as no-flow boundaries due to the known sealing nature of these faults, which is discussed in detail in Section 2.3 of Attachment A.

The remaining Northern and part of the Eastern edges of the model domain were modeled as open boundaries using large volume modifiers at the edge cells to model an infinite aquifer.

3.1.8 Initial Conditions

Initial model conditions (start of CO2 injection) of the Mokelumne River Formation are given in Table 3.2.

Table 3.2. Initial conditions.

Parameter	**Value or Range**	**Units**	**Corresponding Elevation (ft MSL)**	**Data Source**
Temperature	151	Fahrenheit	6,900	Bottom hole temperature data from logs in the area
Formation pressure	2860	Pounds per square inch	6,900	Downhole RFT data from PGE Test injection / Withdrawal well 1 adjusted to depth
Salinity	15,500	Parts per million	6,900	Water analysis and Log calculated salinity curves

3.1.9 Operational Information

Details on the injection operation are presented in Table 3.3. Further details are provided in the Narrative document and in the Operational Procedures Appendix.

Table 3.3. Operating details.

Operating Information	**Injection Well C1**	**Injection Well C2**	**Injection Well E1**	**Injection Well E2**	**Injection Well W1**	**Injection Well W2**
Location (global coordinates)	37°53'18.0988"N 121°32'23.1187"W	37°53'32.0186"N 121°32'21.4924"W	37°53'33.1704"N 121°31'1.6409"W	37°53'32.5242"N 121°30'52.8591"W	37°52'37.6869"N 121°33'34.2543"W	37°52'44.0039"N 121°33'24.6627"W
Model coordinates (ft) X Y	2132846.72 81077.86	2132969.98 82486.69	2139371.35 82636.45	2140075.76 82574.83	2127163.01 76961.37	2127929.06 77604.16
No. of perforated intervals	11	5	14	6	7	8
Perforated interval (ft TVD) Top Bottom	6176 7016	7192 7790	6010 6950	6980 7720	6150 6930	7020 7840
Casing diameter (in.)	7	7	7	7	7	7
Modeled injection period Start End	01/01/2026 01/01/2054	01/01/2026 01/01/2054	01/01/2026 01/01/2036	01/01/2026 01/01/2040	01/01/2026 01/01/2031	01/01/2026 01/01/2042
Modeled Injection duration (years)	28	28	10	14	5	14
Modeled Injection rate (t/day)*	2754	2754	688	688	688	1377
Modeled CO_2 Injected (MMT)	28.2	28.2	2.5	3.5	1.3	7.0

*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).

3.1.10 Fracture Pressure and Fracture Gradient

Calculated fracture gradient and target injection pressure values are given in Table 3.4.

A fracture pressure gradient of 0.76 psi/ft is assumed for the injection zone. This is based on formation integrity tests in the Mokelumne River Formation conducted on wells - Yamada L.W 1, Galli 1 - while drilling in the nearby Union Island Gas field. CTV will conduct a step rate test in the injection zone as part of the pre-operational testing plan to confirm this fracture pressure gradient.

At this time, no fracture gradient information has been found for the Capay shale. CTV will conduct a step rate test for the Capay Shale as part of the pre-operational testing.

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection wells (Table 3.4). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 3.4. Injection pressure details.

Injection Pressure Details	**Injection Well C1**	**Injection Well C2**	**Injection Well E1**	**Injection Well E2**	**Injection Well W1**	**Injection Well W2**
Fracture gradient (psi/ft)	0.76	0.76	0.76	0.76	0.76	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4224	4919	4111	4774	4207	4802
Elevation corresponding to maximum injection pressure (ft TVD)	6178	7192	6011	6984	6155	7020
Elevation at the top of the perforated interval (ft TVD)	6178	7192	6011	6984	6155	7020
Calculated maximum injection pressure at the top of the perforated interval (psi)	4224	4919	4111	4774	4207	4802
Planned injection pressure (psi) / gradient (psi/ft) at top of perforations	3050 / 0.494	3566 / 0.496	2901 / 0.483	3363 / 0.482	2961 / 0.481	3504 / 0.499

3.2 Computational Modeling Results

3.2.1 Predictions of System Behavior

Figure3.12 and **Figure 3.13** show the computational modeling results and development of the CO_2 plume at different time steps. The boundaries of the CO_2 plume have been defined with a 0.01 CO_2 global mole fraction cutoff.

As shown in **Figure 3.12**, the CO_2 extent is largely defined by Year 52 after the end of injection. The majority of the CO_2 injectate remains as super-critical CO_2 (83%) with the remaining portion of the CO_2 dissolving in the formation brine over the simulated 100 years post injection.

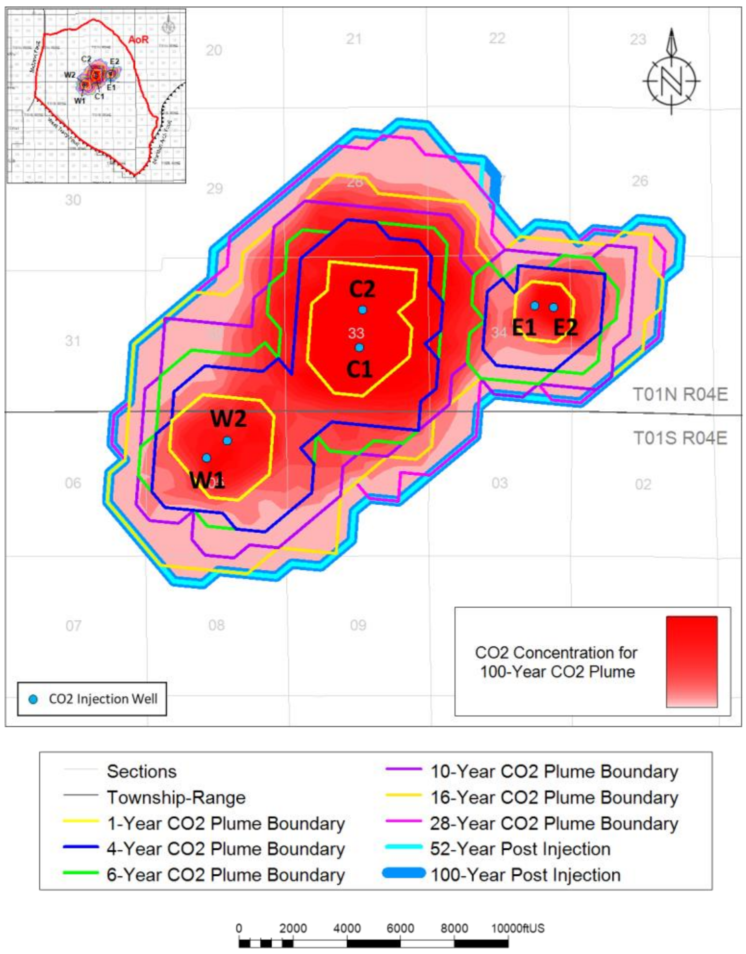


Figure 3.12: Plume development through time: 1-year, 4-year, 6-year, 10-year, 16-year, 28-year (end of injection), 52-year post injection and 100-year post injection.

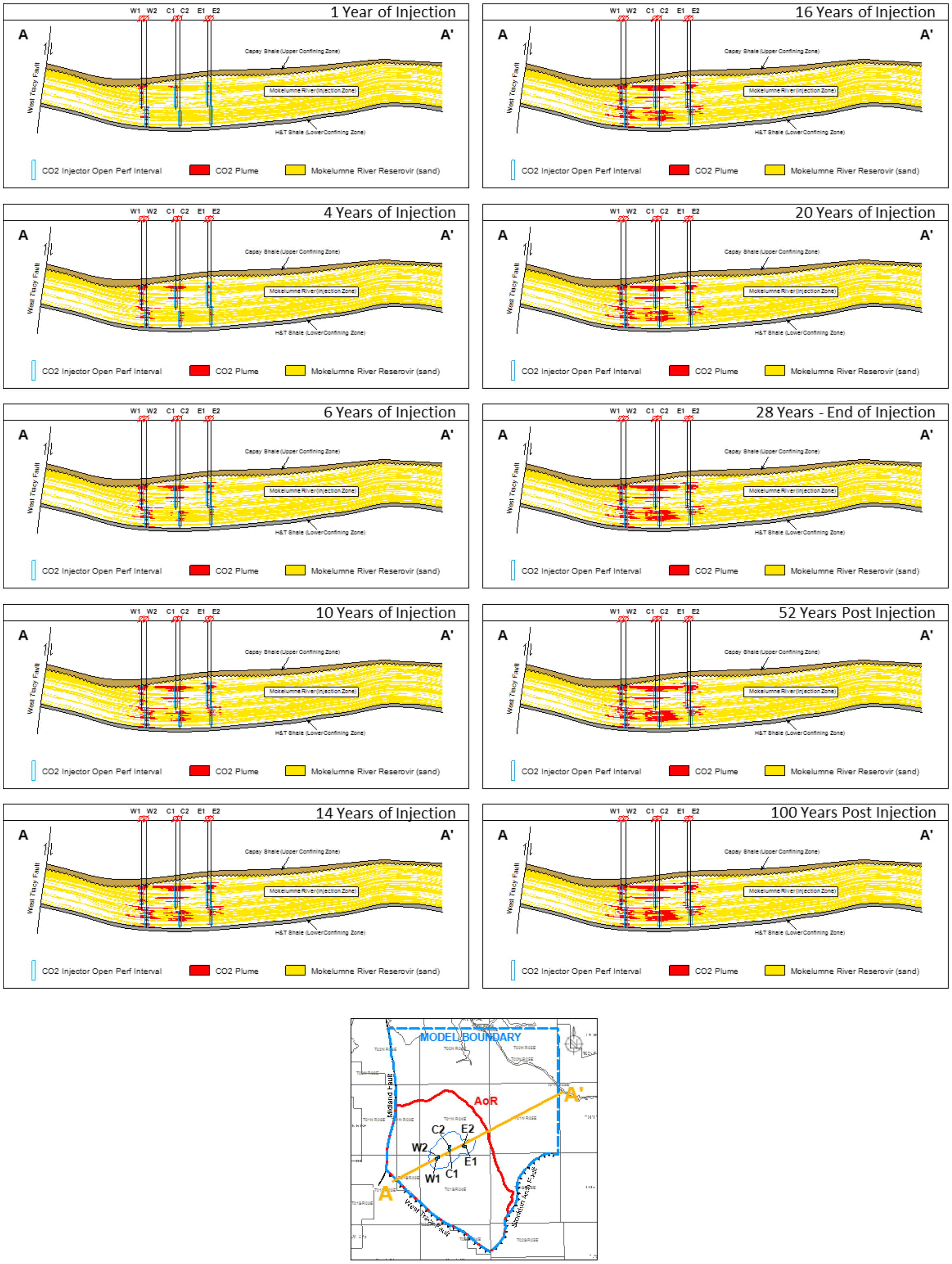


Figure 3.13. Cross-sections showing plume development at various time steps through the project.

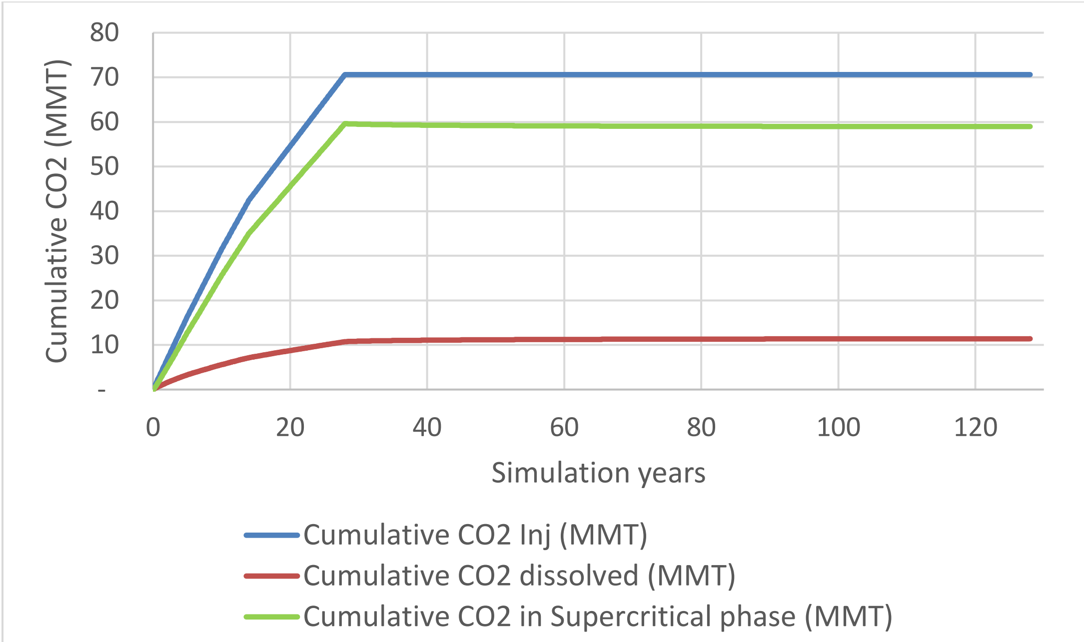


Figure 3.14. CO_2 storage mechanisms in the reservoir.

3.2.2 Model Calibration and Validation

The model inputs were compared against publicly available reports by Lawrence Berkley National Laboratory (LBNL) and the West Coast Regional Carbon Sequestration Partnership (WestCARB) investigating the CCS potential of the Mokelumne River and other formations in the nearby King Island Gas field. The results of CTV's simulation compare favorably against the previous work by LBNL regarding storage capacity and CO_2 plume size.

3.2.2.1 CO_2 Injectate effect on Plume and AoR modeling results

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.
The CO2 plume for Injectate 1 and Injectate 2 is consistent with the plume outline for 100% CO2 injectate (Figure 1), which was defined by a 0.05 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 1. The wells that fall within the CO2 plume are the same for all 3 cases.
Similarly, the AoR was delineated using Critical pressure for the 3 cases and was found to be consistent. Details on the Critical pressure calculation method are discussed in the "Attachment B – AoR and Corrective Action" document. Figure 3.15 shows the AoR boundary for the 3 cases. Additionally, the average Pore Volume pressure within the approximate AoR boundary was plotted for the 3 cases and was found to be very close with a maximum difference of ~3 psi seen between the cases, as shown in Figure 3.16. Multiple scenarios were also ran to test the effect of mixing Injectate 1 and Injectates 2 in different ratios on the AoR boundary and plume shapes. As expected, since the resulting mixed injectates were still high purity CO2 streams with impurity concentrations in-between those of Injectates 1 and 2, the AoR boundaries and Plume shapes for

these scenarios were within the envelope represented by the end point compositions - Injectate 1 and 2.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling and will do so for any additional sources. In addition, the AoR will be reviewed as per section 3.4 Reevaluation Schedule and Criteria section.

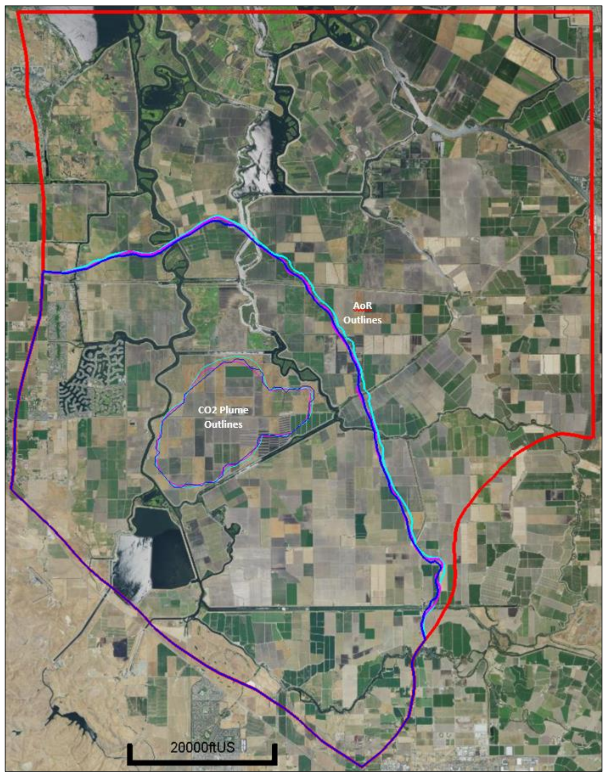


Figure 3.15: AoR boundaries and CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Pink) and 100% CO2 Cases (Dark Blue). Larger Red outline is the model boundary. Minimal difference in AoR boundaries between the 3 cases with the boundaries overlying each other for the most part

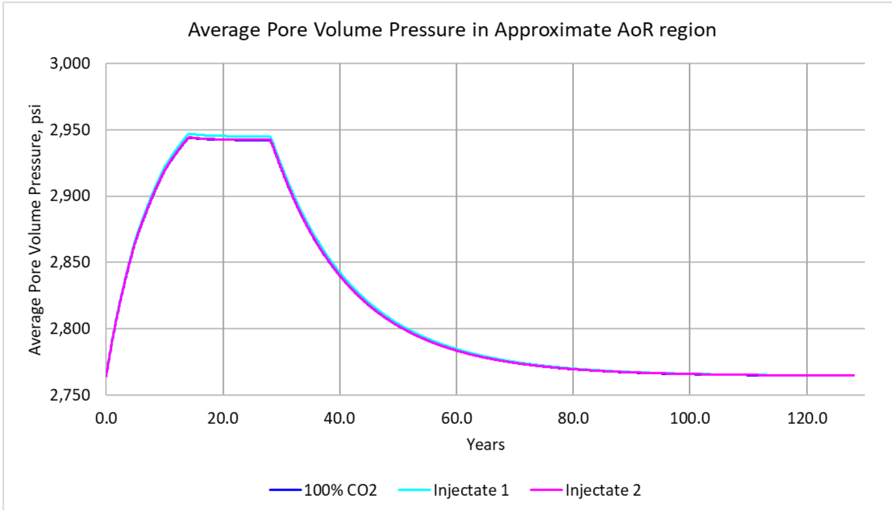


Figure 3.16: Average reservoir pressure within approximate AoR for Injectate 1, Injectate 2 and 100% CO2 cases. 100% CO2 case and Injectate 2 case pressure trends plot almost on top of each other.

3.2.2.2 Sensitivity cases

In addition, scenarios were run to test the effect of varying major model inputs on the CO_2 plume and AoR extent.

Table 3.5. Simulation sensitivity scenarios

Scenario	CO_2 plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

These scenarios and the comparison against previous work in the area provides us with confidence in the CO_2 plume extent and AoR, and that the corrective action well review and potential impact to the USDW has been appropriately evaluated.

3.2.3 AoR Delineation

The AoR delineation was based on the methods of Nicol et al. (2008), which is referenced in the US EPA AoR and Corrective Action Guidance. Based on pressure data available in the Mokelumne River Formation in the region (**Figure 3.18**), it appears that the formation is under-pressured. Graph and data table showing this are shown in **Figure 3.17**. This is likely due to historic withdrawal from the Mokelumne River formation from regional Gas field operations in the area, and limited recharge.

Well	Measured Depth TVD	Measured Res Press, psi	Pressure measurement method	Date measured
PGE Test Inj/withdrawal well 1	4,664	1,892	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,673	1,895	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,678	1,898	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,716	1,914	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,741	1,925	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,763	1,934	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,779	1,941	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,787	1,945	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,854	1,974	Formation test	10/19/2014
RVGU_198	4,857	1,663	Formation test	1/21/1996
RVGU_198	4,899	1,671	Formation test	1/21/1996
RVGU_198	4,912	1,673	Formation test	1/21/1996
RVGU_198	4,924	1,678	Formation test	1/21/1996
RVGU_198	4,957	1,729	Formation test	1/21/1996
McDonald Farms 9	5,270	1,960	Operator Pressure estimate	8/20/2016

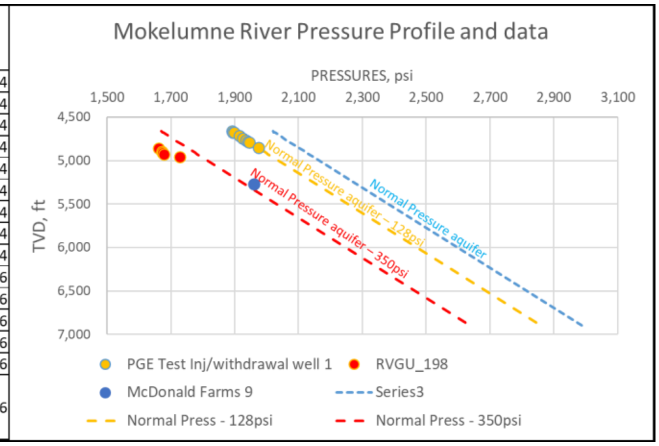


Figure 3.17. Mokelumne River Formation pressure profile and data

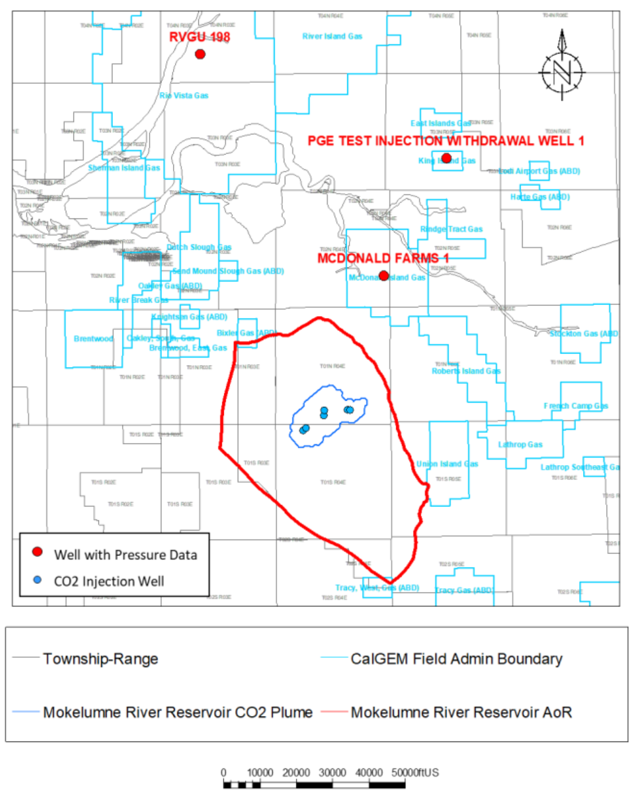


Figure 3.18. Map showing location of wells with pressure data for the Mokelumne River Formation.

For the purpose of calculating the critical pressure and delineating the AoR for the project area, the aquifer was considered to be under-pressured by 128 psi, and the following equations were used to calculate critical pressure across the model domain:

$$\Delta P_{C,norm} = g(Z_V - Z_I)[\frac{\lambda-\xi}{2}(Z_V - Z_I) + \rho_{I,\lambda} - \rho_I] \quad \text{– Eq (1)}$$

$$\Delta P_c = \Delta P_{C,norm} + \Delta P_u \quad \text{– Eq (2)}$$

Where,

$\Delta P_{C,norm}$	-	the admissible overpressure in a normally pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit
ΔP_c	-	the admissible overpressure in an under-pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit
ΔP_u	-	the difference of normal pressure to actual pressure in the under-pressured aquifer, assumed 128psi across the model domain
g	-	acceleration due to gravity, 9.81m/s^2
Z_V	-	Elevation of the injection zone
Z_I	-	Elevation of the base of the USDW
λ	-	density gradient in the conduit at constant injection zone brine TDS
ξ	-	density gradient in the conduit at initial condition
$\rho_{I,\lambda}$	-	Density of the injection zone brine at USDW depth
ρ_I	-	Density of the brine in the conduit at USDW depth at initial condition

An average TDS of 15,500ppm was assumed for the injection zone and an average TDS of 7,900ppm was assumed for the USDW based on Salinity calculations in the project area. Injection zone and USDW depths were based on the model grid and USDW mapping in the project area. Density and density gradients were calculated as a function of temperature and salinity using standard methods (McCutcheon et. al. 1993). Using these, the critical pressure was calculated at each grid point in the Petrel model using **Equations 1 & 2**, and combined with the pressure outputs from the plume simulation to delineate an AoR boundary at different timesteps. The final AoR boundary was based on the outermost threshold overpressure 14 years into the injection which is when the maximum extent was seen. **Figure 3.19** shows the AoR extent, CO_2 plume extent, injector locations and proposed monitoring well locations. Details on the monitoring wells are discussed in further detail in Attachment C – Testing and Monitoring Plan.

Approximately 50 years after the end of injection, the pressure buildup in the reservoir dissipates to nearly zero.

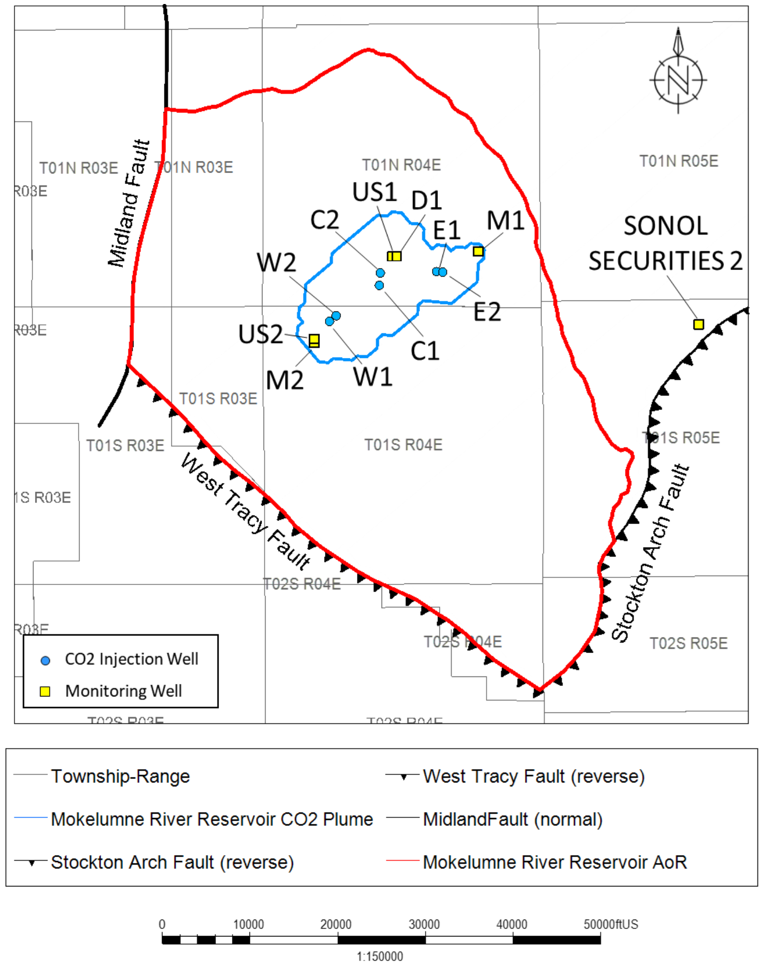


Figure 3.19: Map showing the location of injection wells and monitoring wells.

3.3 Corrective Action

3.3.1 Tabulation of Wells within the AoR

Wells within the AoR are associated with exploration of the Mokelumne River and Winters Formations for natural gas accumulations. Nearby, commercial discoveries of natural gas were developed from 1936 onwards. As such, there are excellent records for wells drilled in the study area. There have been no undocumented historical wells found in the AoR.

CTV accessed internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR.

Table 3.6 provides counts of the AoR wellbores by status and type, for each wellbore with a unique API-12 identifier. Appendix B-1 provides a complete list of all wellbores by API-12 within the AoR. As required by 40 CFR 146.84(c)(2), the well table in Appendix B-1 describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to the Mokelumne River Formation 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 3.6: Wellbores in the AoR by Status

Status	Count
Active	0
Idle	0
Plugged and Abandoned	46
Total	**46**

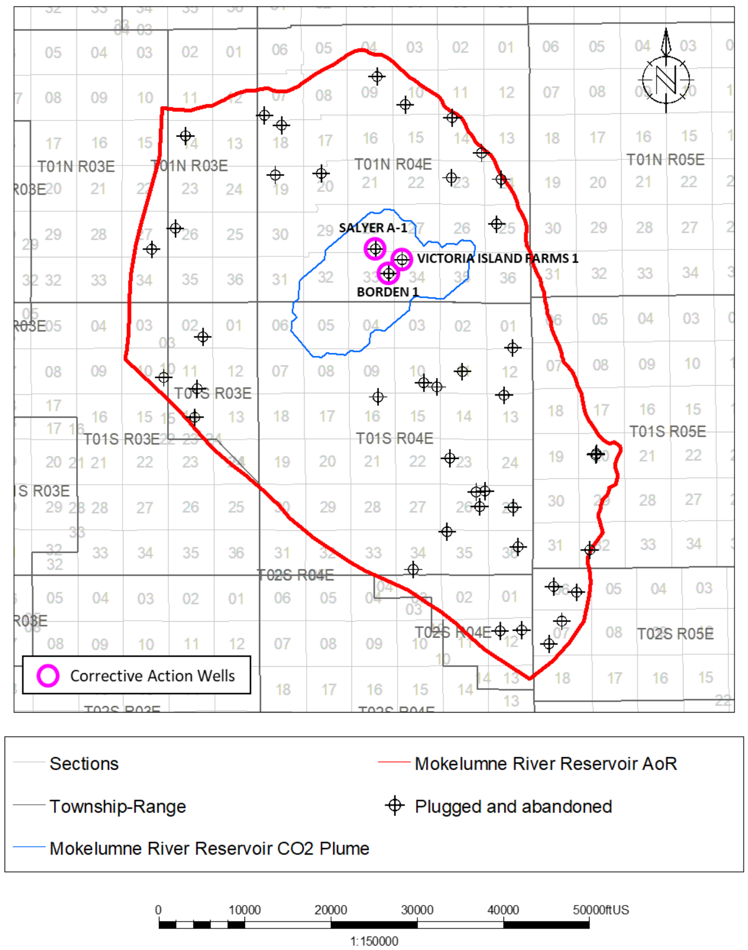


Figure 3.20. Wells penetrating the Capay Shale confining layer and Mokelumne River Formation sequestration reservoir reviewed for corrective action. Wells requiring corrective action prior to injection are identified by magenta circles.

3.3.2 Protection of USDW

For the project area, CTV assessed USDW protection by evaluating all wellbores that penetrate the confining Capay Shale. The corrective action assessment included the generation of detailed casing diagrams for each wellbore, review of all perforations, top of cement assessment for each casing string, and determination of cement plug depths. Non-endangerment of USDW will be ensured during all stages of the project.

3.3.3 Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating the Capay Shale was determined by interpretation of open-hole well logs and utilizing the deviation survey. All wells in the AoR penetrate the Capay Shale confining zone. These wells also penetrate the Mokelumne River Formation storage reservoir.

3.3.4 Mokelumne River Formation Isolation

All forty-six wells within the AOR penetrate the Mokelumne River Formation, and none will be used for the project. If isolation of this formation is determined to be deficient in such a way that USDW may be impacted, corrective action plans will be communicated and implemented prior to injection to ensure non-endangerment of USDW.

3.3.5 Corrective Action Assessment of Wells in AoR

Three wells located within the CO_2 plume, shown in Figure 3.20, were drilled as gas exploration wells and determined to be dry holes (no hydrocarbon present).The surface casing was set above the base of USDW, and because commercial hydrocarbons were not present, production casing was not installed. The wells were abandoned with the placement of a cement plug at the top of the openhole section extending into the surface casing. CTV proposes to re-enter these three wells, drill out the plugs, and re-plug them to ensure non-endangerment of USDW. Under the CTV proposed plan, the three wellbores will be filled with Class G portland cement plugs from the injection zone and/or confining layer upward into the surface casing. Attachment B-3 shows diagrams for the current well configuration and proposed corrective action.

For the wells in the AoR and outside the CO_2 plume, CTV will provide a strategy and/or corrective action plan on these wells during pre-operational testing. The implementation and results of the corrective acion plan for the three wells located within the CO_2 plume will inform the corrective action assessment and planning of these wells. A map with these wells is shown in Figure 3.20, and the table of wells in Appendix B-1 provides well information pursuant to 40 CFR §146.84(c)(2).

3.3.6 Plan for Site Access

CTV has obtained surface access rights for the duration of the project.

3.3.7 Corrective Action Schedule

Corrective action will be completed on the three wells within the CO_2 plume prior to injection. The plan for the remaining forty-three wells will be addressed during pre-operational testing. CTV will ensure that CO_2 is confined to the injection zone within the 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.

3.4 Reevaluation Schedule and Criteria

3.4.1 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 CO_2 content/saturation (to evaluate the potential for unexpected 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.

3.4.2 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 Mokelumne River Formation reservoir that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

    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 within six months of an event 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.

AREA OF REVIEW AND CORRECTIVE ACTION - FIGURES

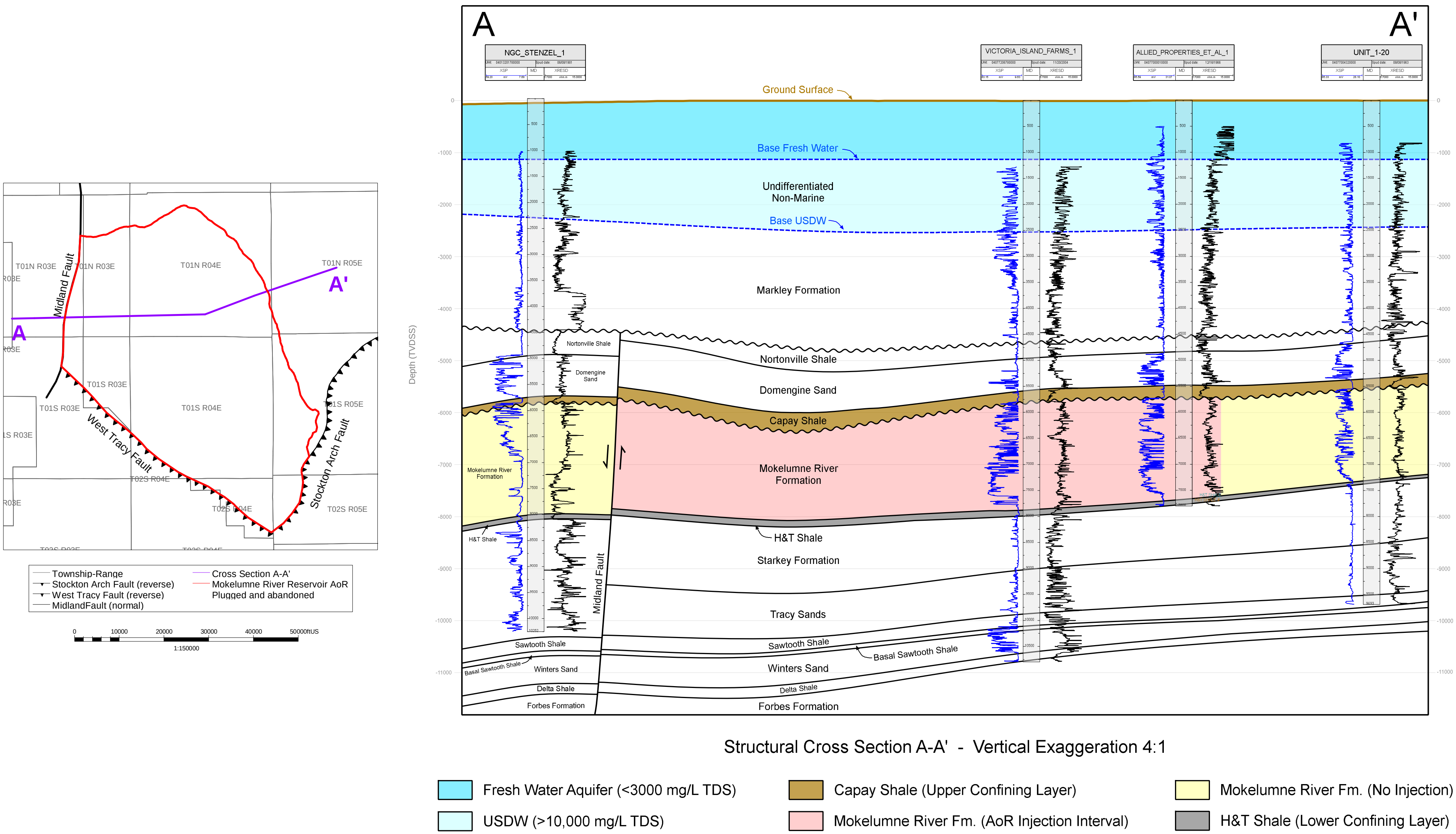


Figure 3.1. Cross section showing stratigraphy and lateral continuity of major formations across the AoR.

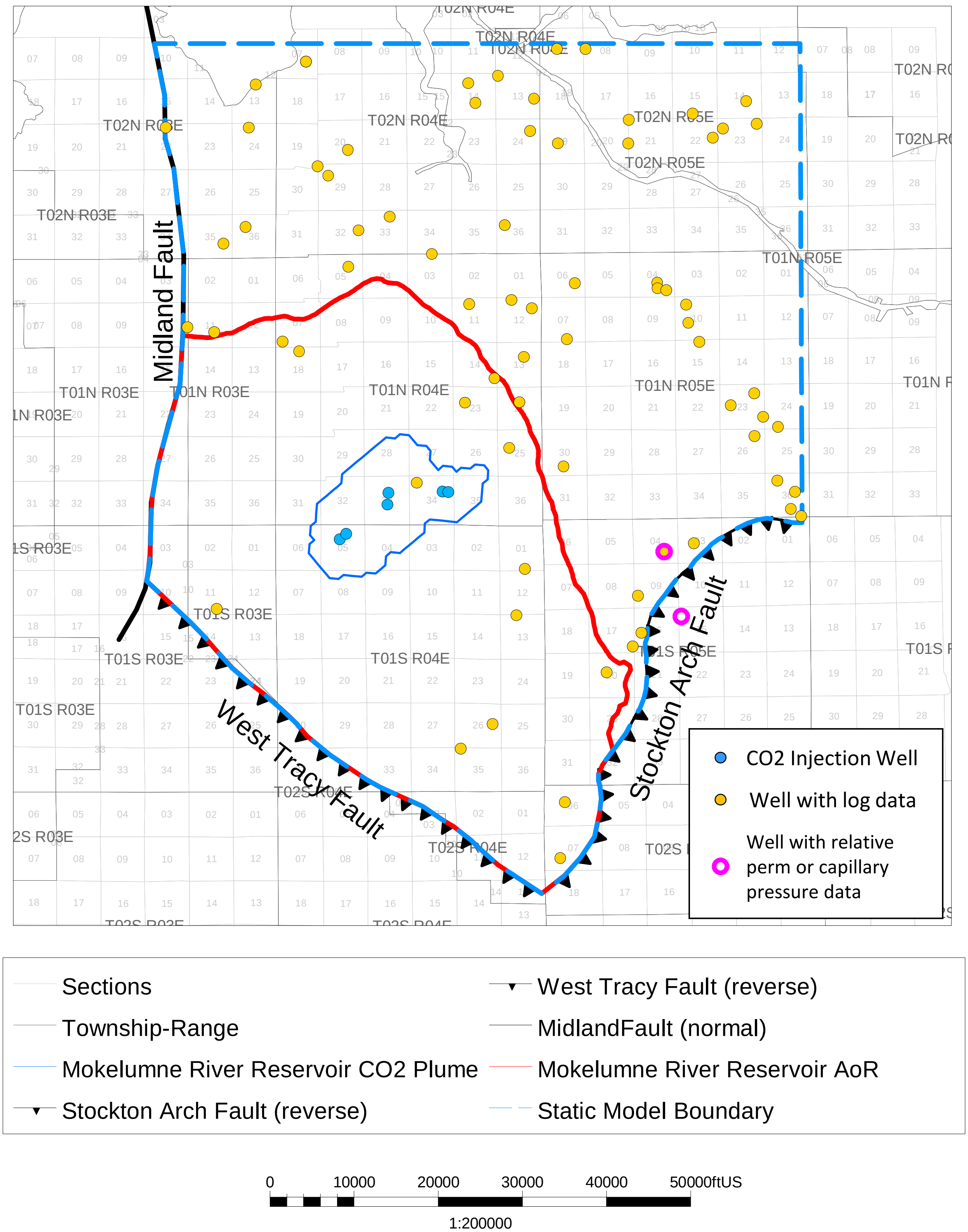


Figure 3.2. Location of wells with open-hole log data and Winters zone relative permeability or capillary pressure data used to develop the static and computational models.

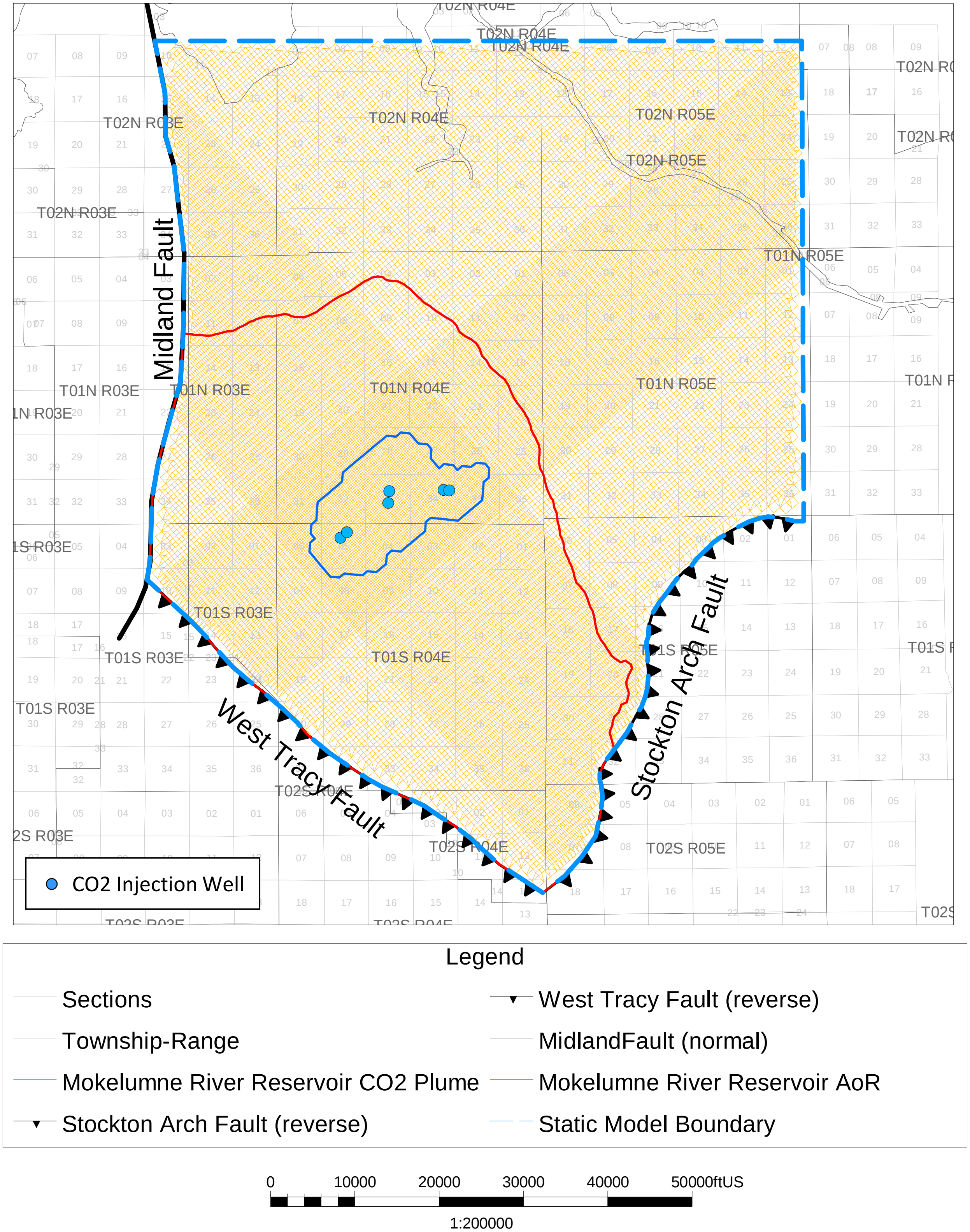


Figure 3.3. Plan view of the model boundary and geo-cellular grid used to define the CO2 plume extent and associated AoR.

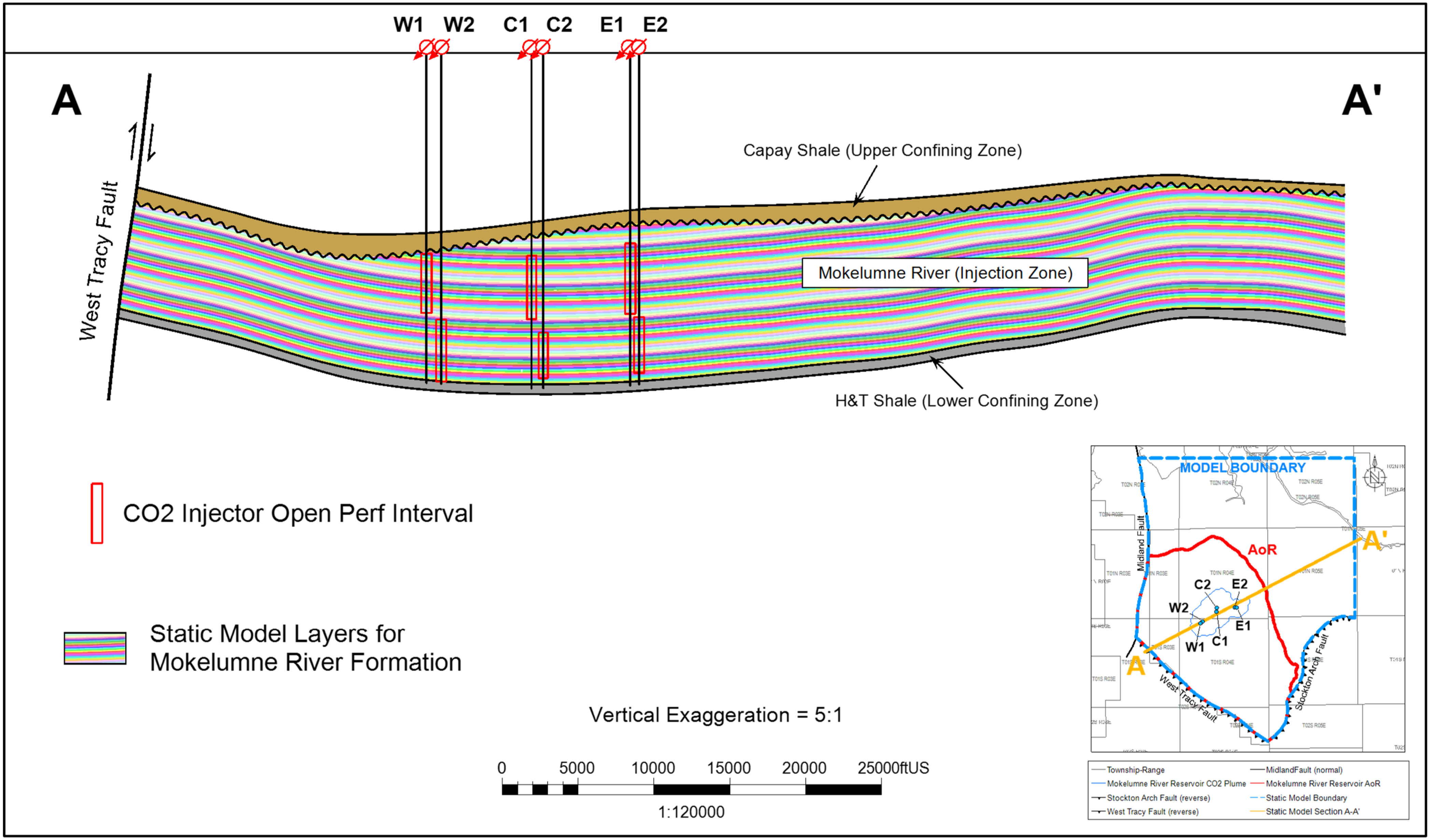
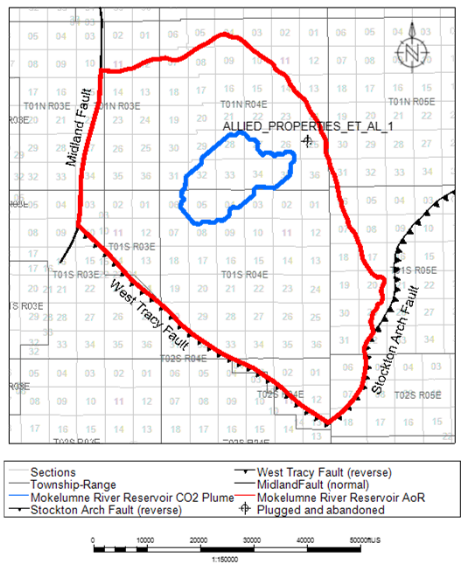


Figure 3.4. Static model grid layering of the Mokelumne River formation. Stratigraphic units are bound to the west, southwest, and southeast by the Midland, West Tracy, and Stockton Arch faults, respectively.



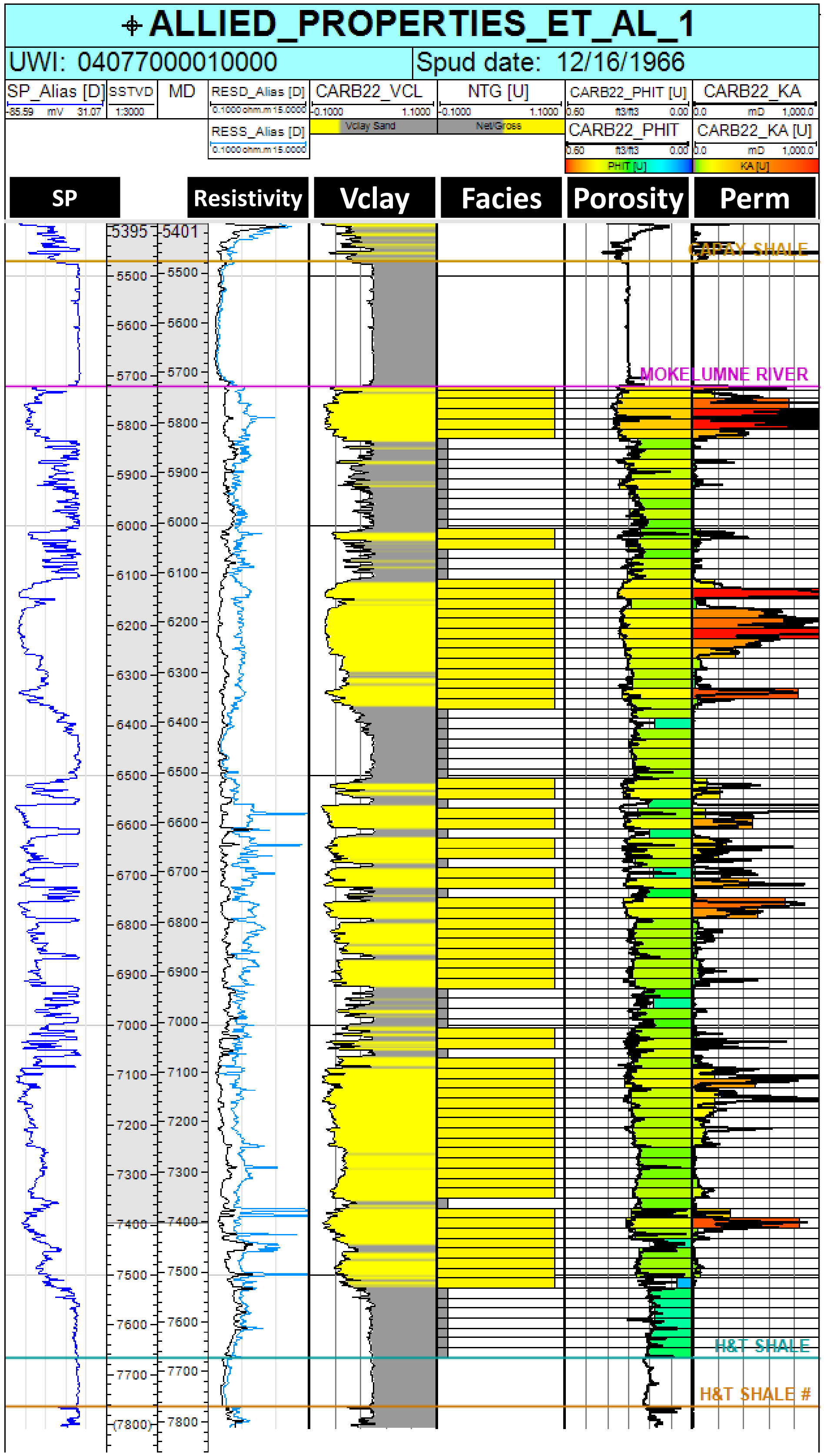


Figure 3.5. Well “Allied Properties Et Al 1” upscaled logs versus open-hole logs.

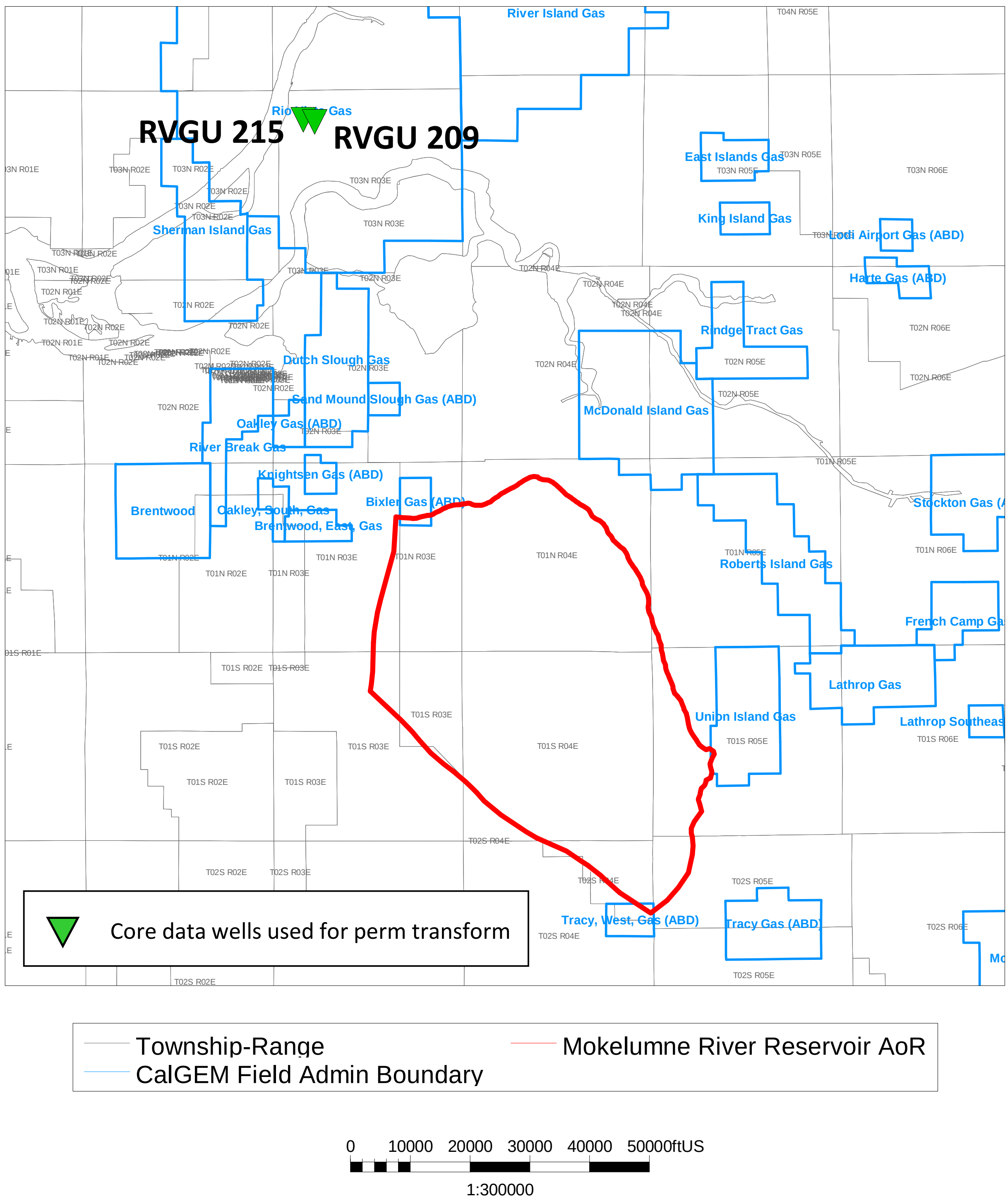


Figure 3.6. Location of wells with core data used for permeability transform.

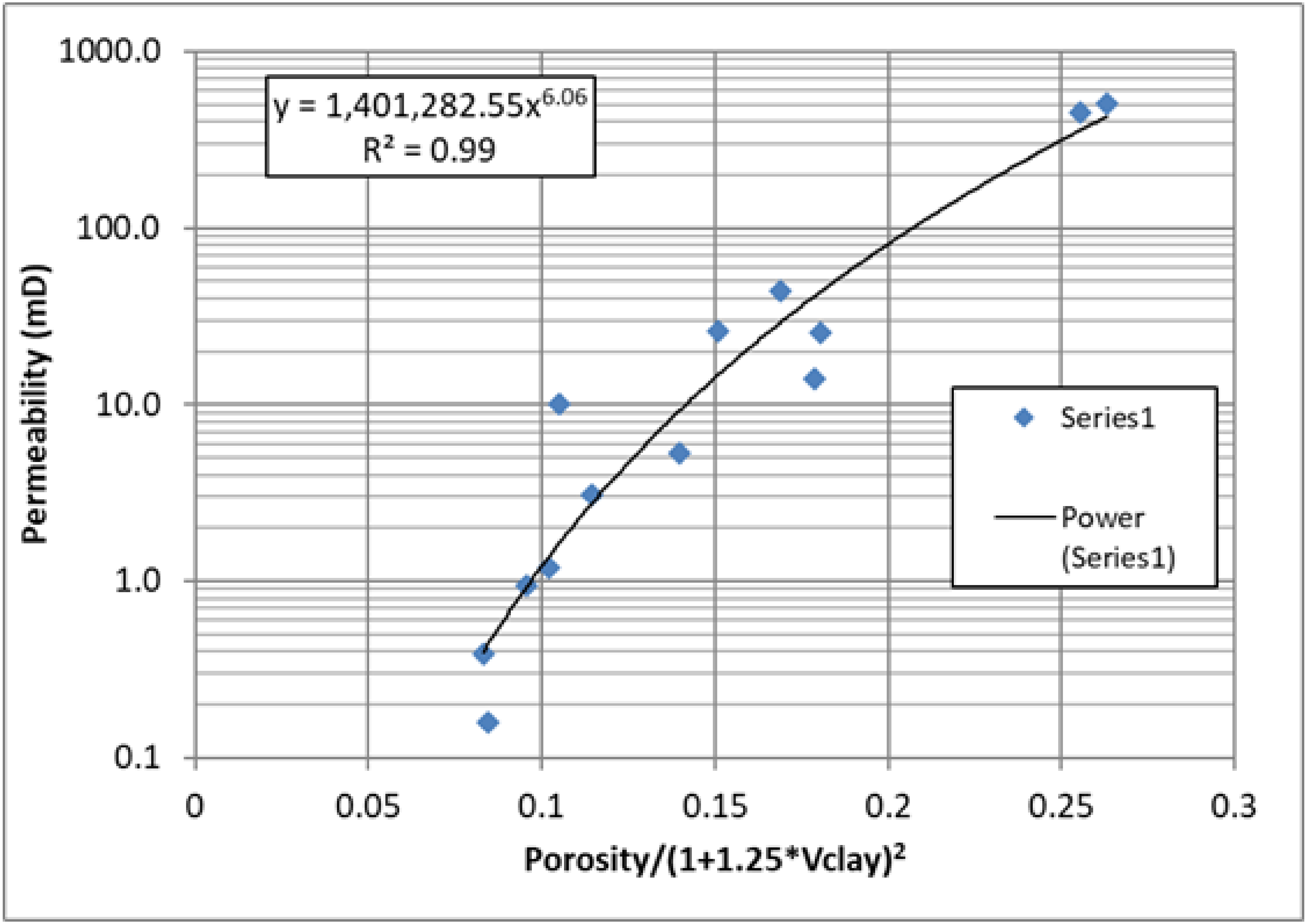


Figure 3.7. Permeability transform for Sacramento Basin zones.

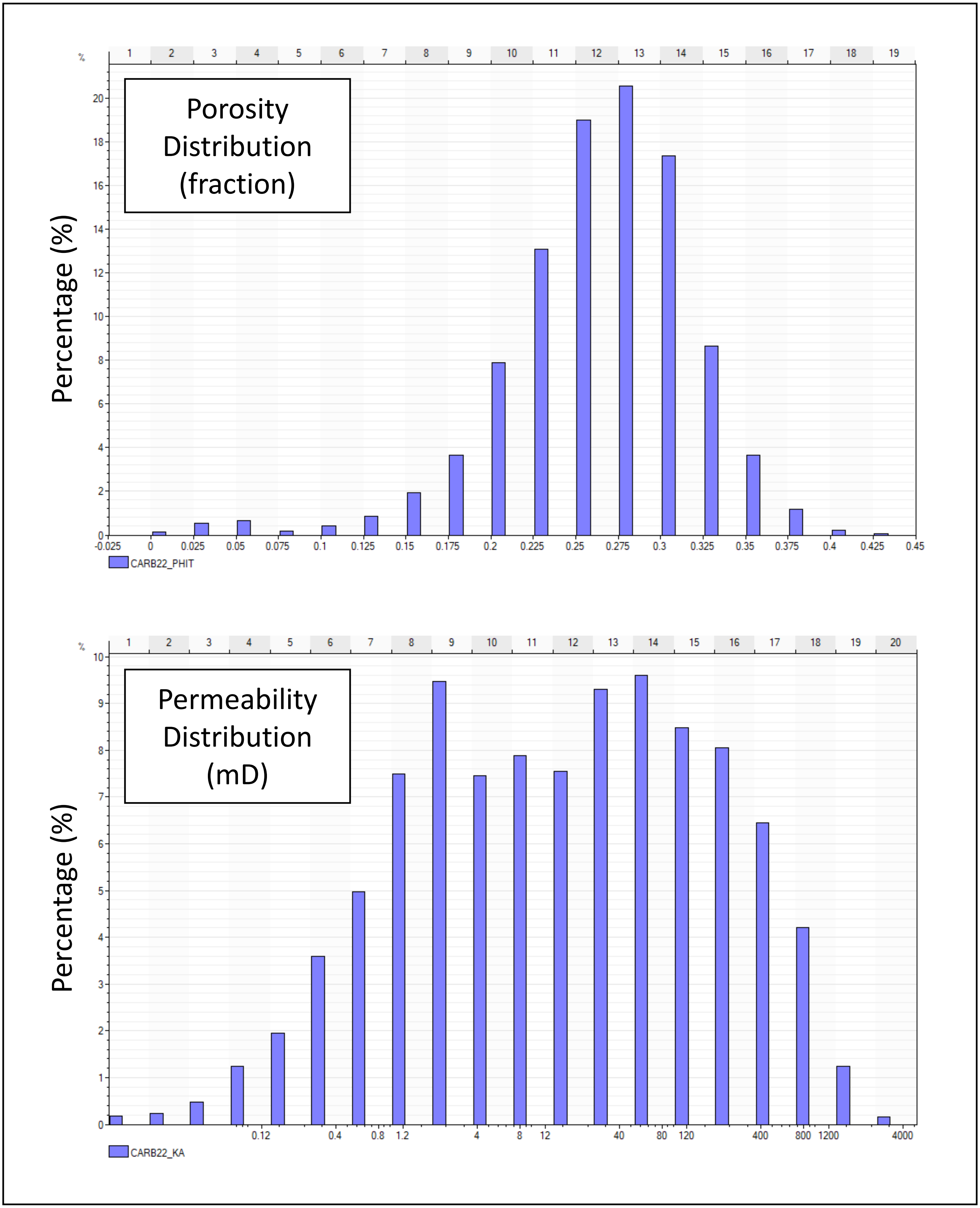


Figure 3.8. Mokelumne River Formation porosity and permeability distribution in the static model.

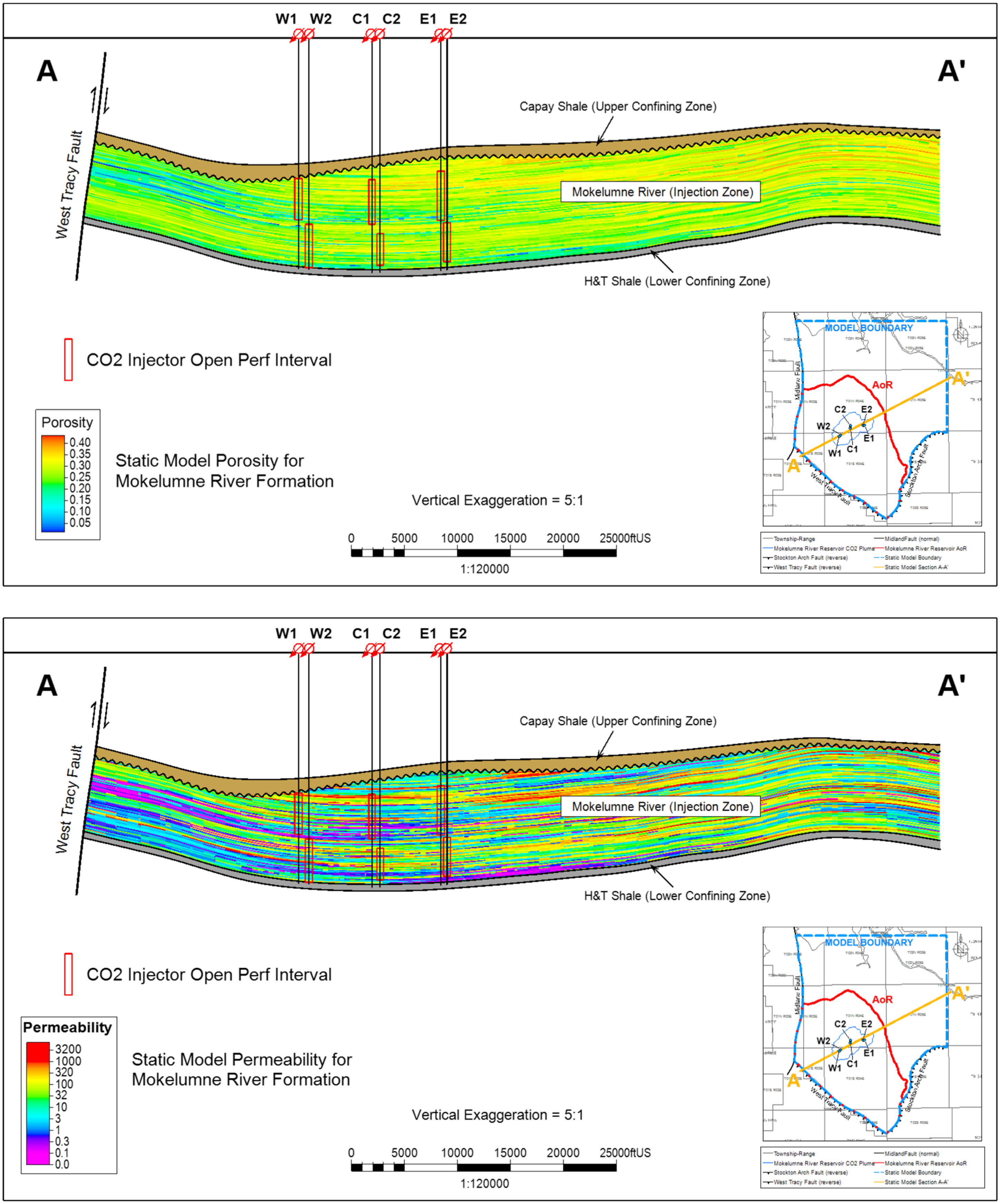


Figure 3.9. Sections through the static grid showing the distribution of porosity and permeability in the reservoir.

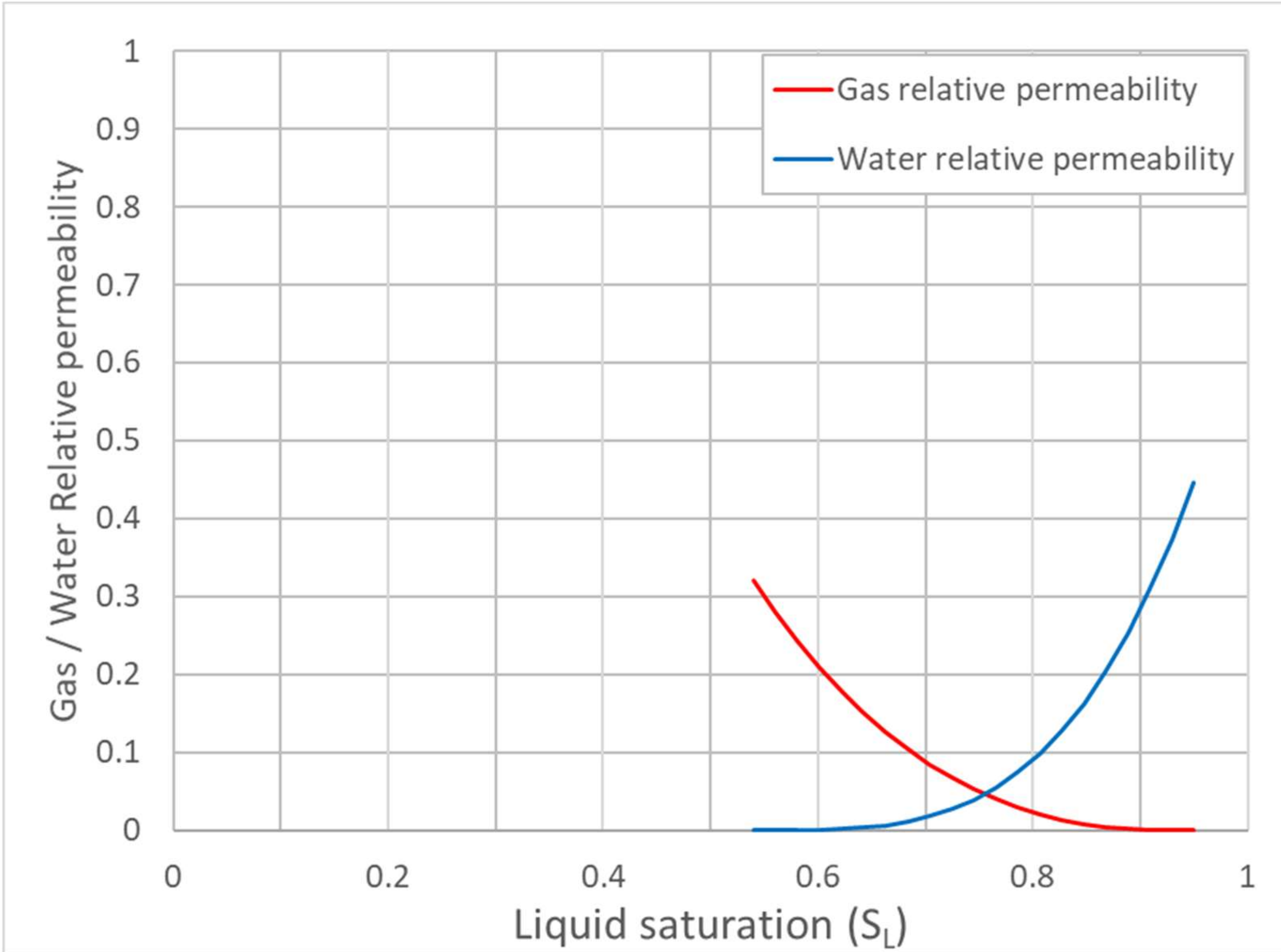


Figure 3.10: Relative permeability curves for Gas-Water system

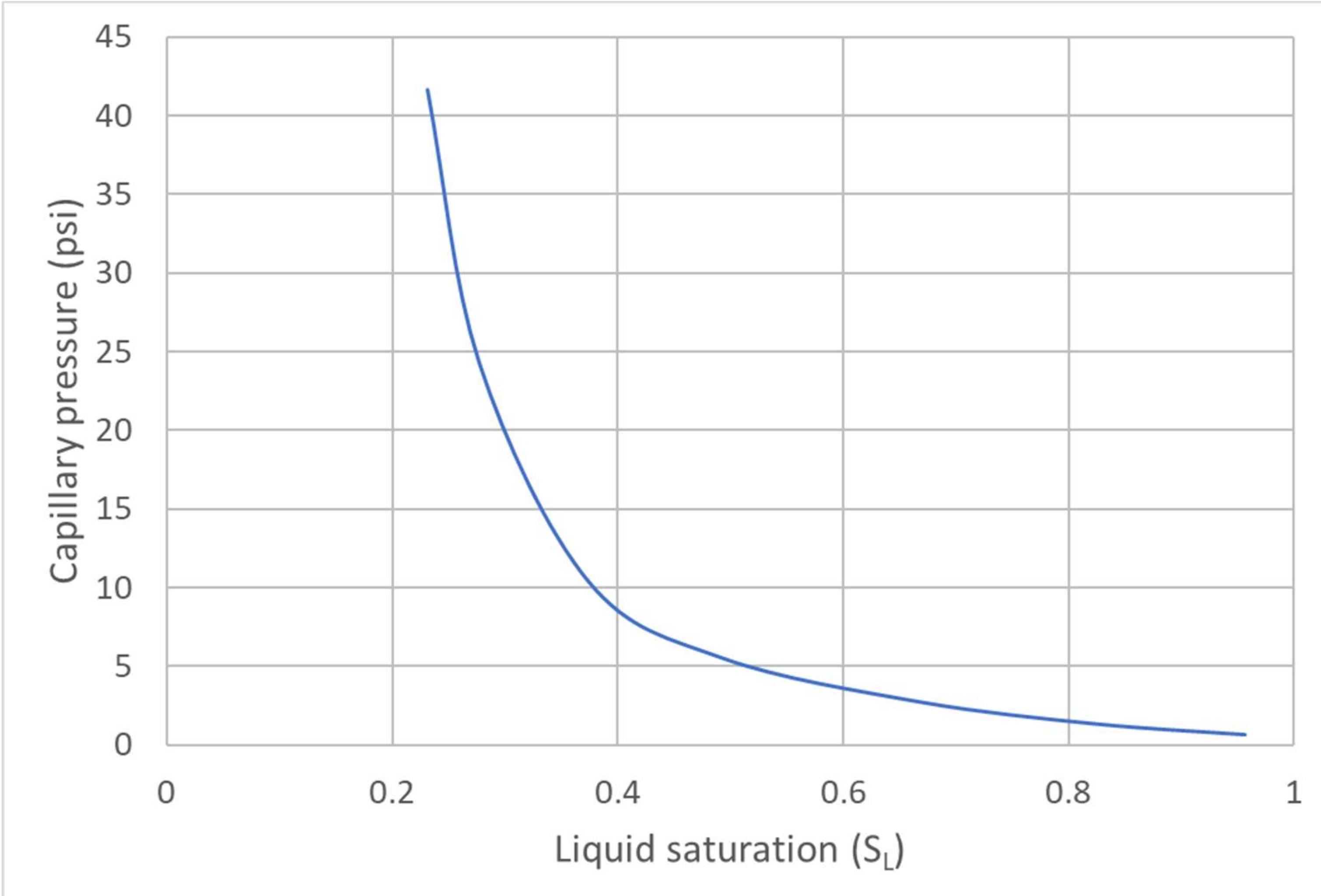


Figure 3.11: Capillary pressure curve

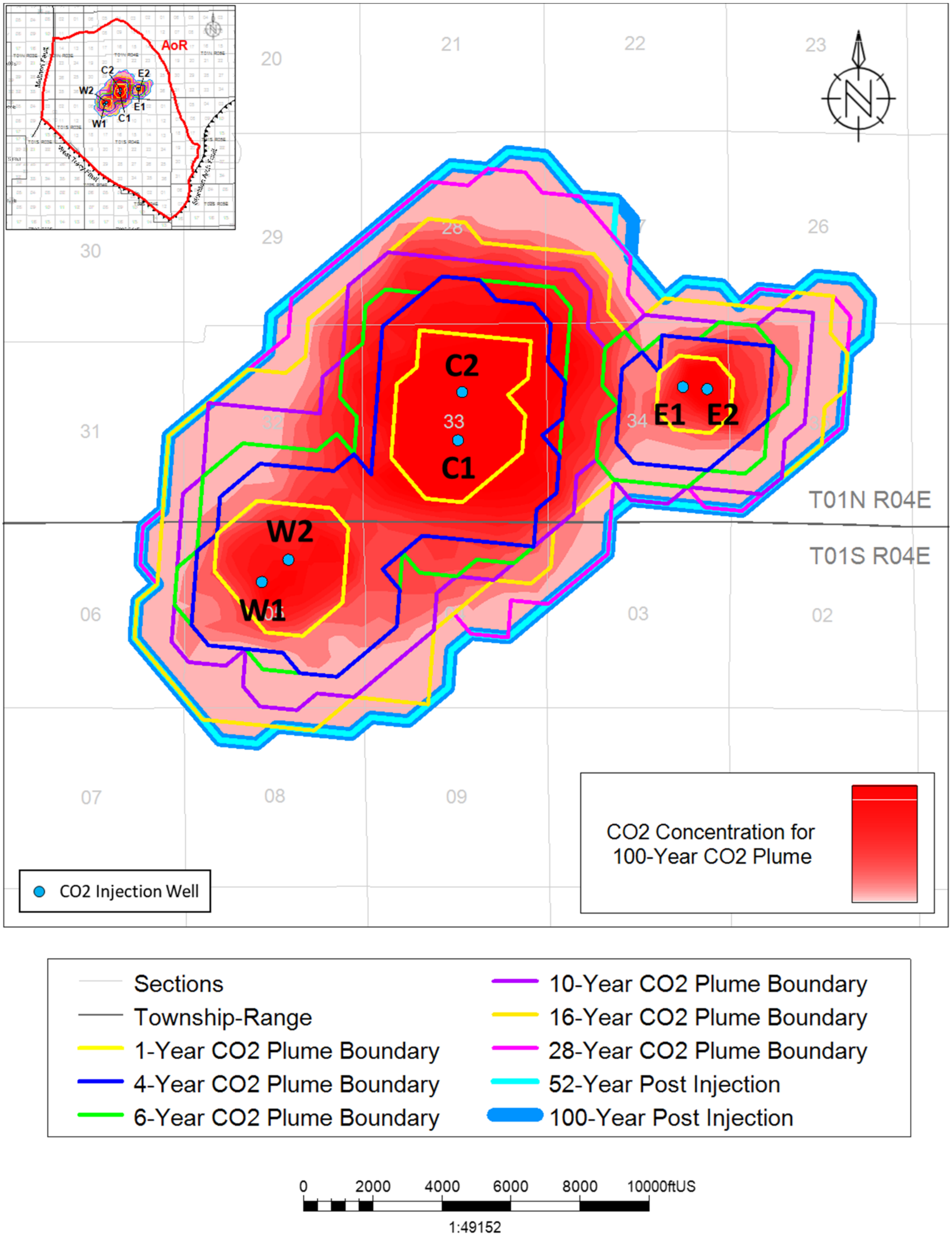
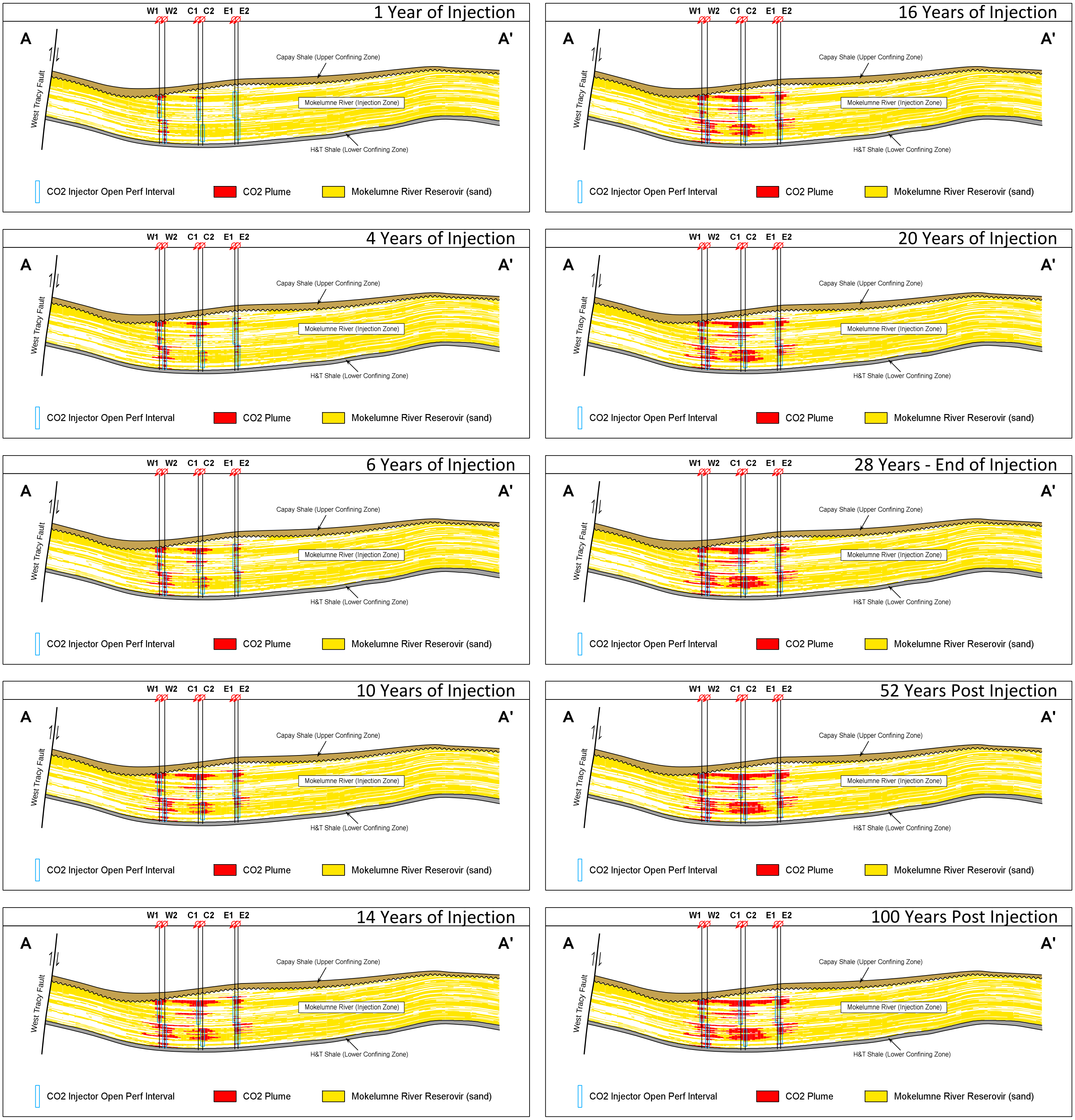


Figure 3.12. Plume development through time (1-year, 4-year, 6-year, 10-year, 16-year, 28-year (end of injection), 52-year post injection and 100-year post injection.



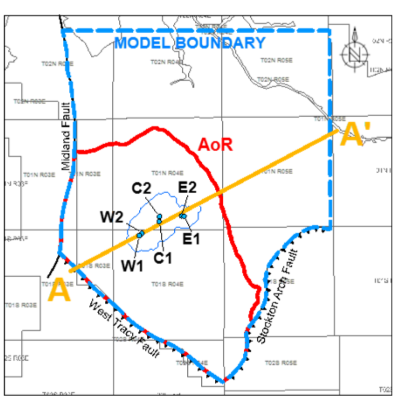


Figure 3.13. Cross sections showing plume development at varying time steps through the project.

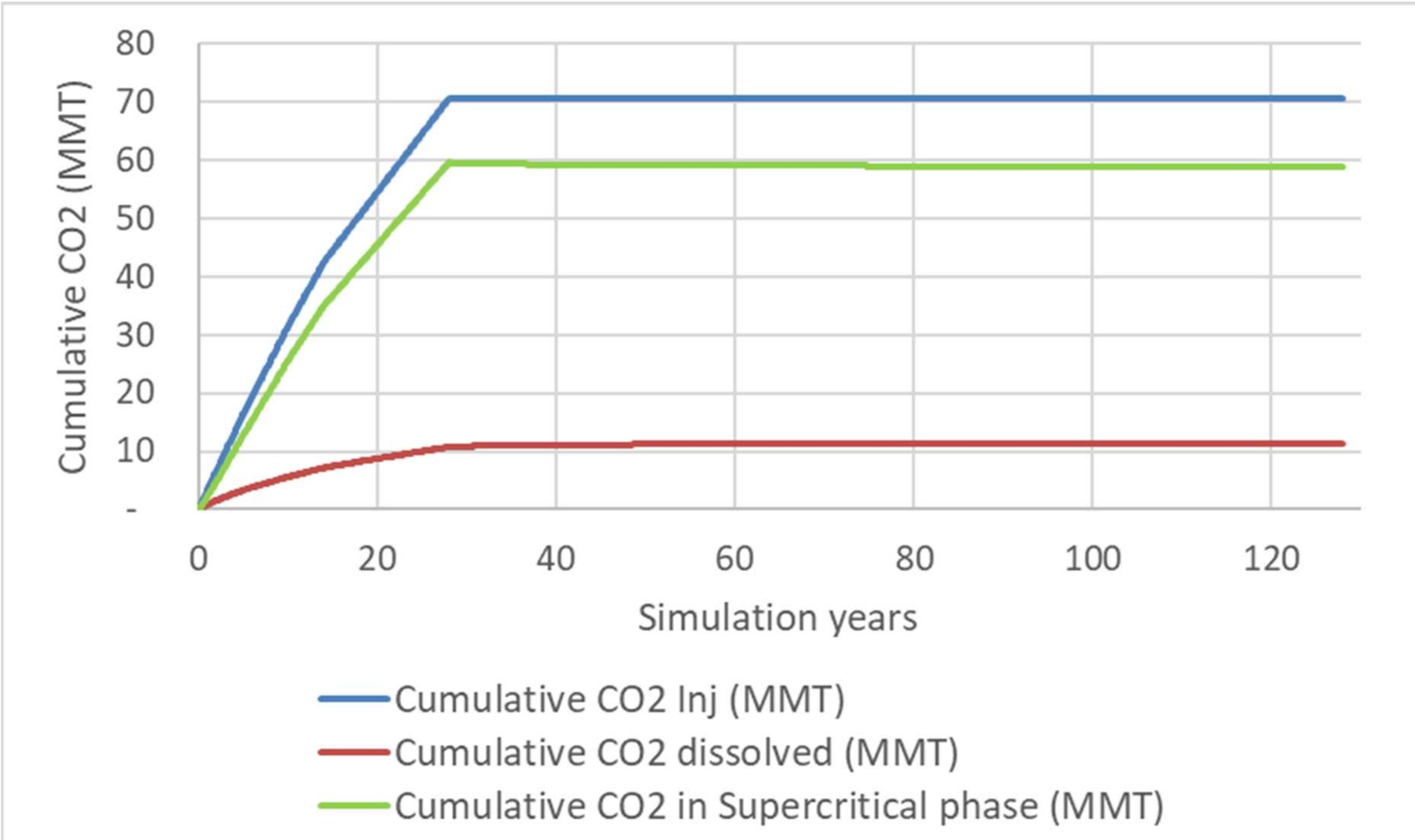


Figure 3.14: CO2 storage mechanisms in the reservoir

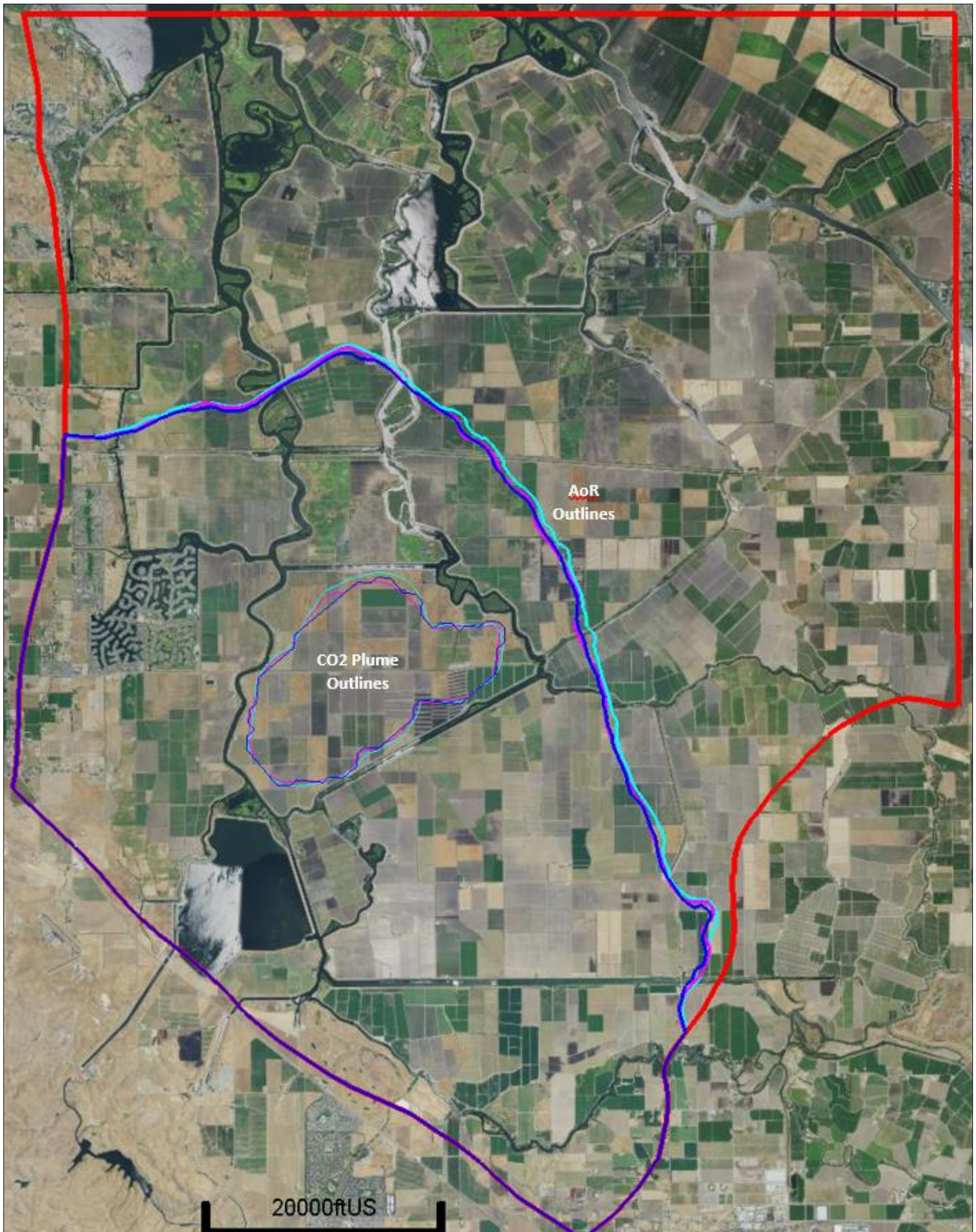


Figure 3.15: AoR boundaries and CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Pink) and 100% CO2 Cases (Dark Blue). Larger Red outline is the model boundary. Minimal difference in AoR boundaries between the 3 cases with the boundaries overlying each other for the most part

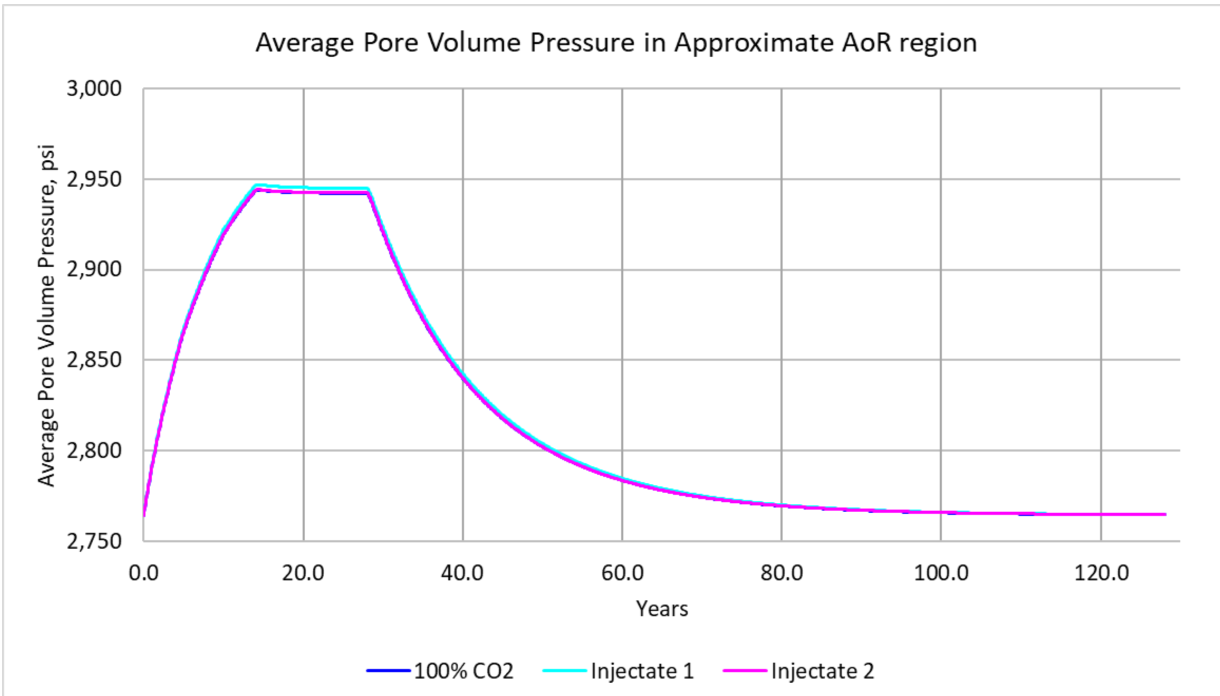


Figure 3.16: Average reservoir pressure within approximate AoR for Injectate 1, Injectate 2 and 100% CO2 cases. 100% CO2 case and Injectate 2 case pressure trends plot almost on top of each other.

Well	Measured Depth TVD	Measured Res Press, psi	Pressure measurement method	Date measured
PGE Test Inj/withdrawal well 1	4,664	1,892	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,673	1,895	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,678	1,898	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,716	1,914	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,741	1,925	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,763	1,934	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,779	1,941	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,787	1,945	Formation test	10/19/2014
PGE Test Inj/withdrawal well 1	4,854	1,974	Formation test	10/19/2014
RVGU_198	4,857	1,663	Formation test	1/21/1996
RVGU_198	4,899	1,671	Formation test	1/21/1996
RVGU_198	4,912	1,673	Formation test	1/21/1996
RVGU_198	4,924	1,678	Formation test	1/21/1996
RVGU_198	4,957	1,729	Formation test	1/21/1996
McDonald Farms 9	5,270	1,960	Operator Pressure estimate	8/20/2016
SERPA 5	6,900	2,947	Formation test	10/11/2012

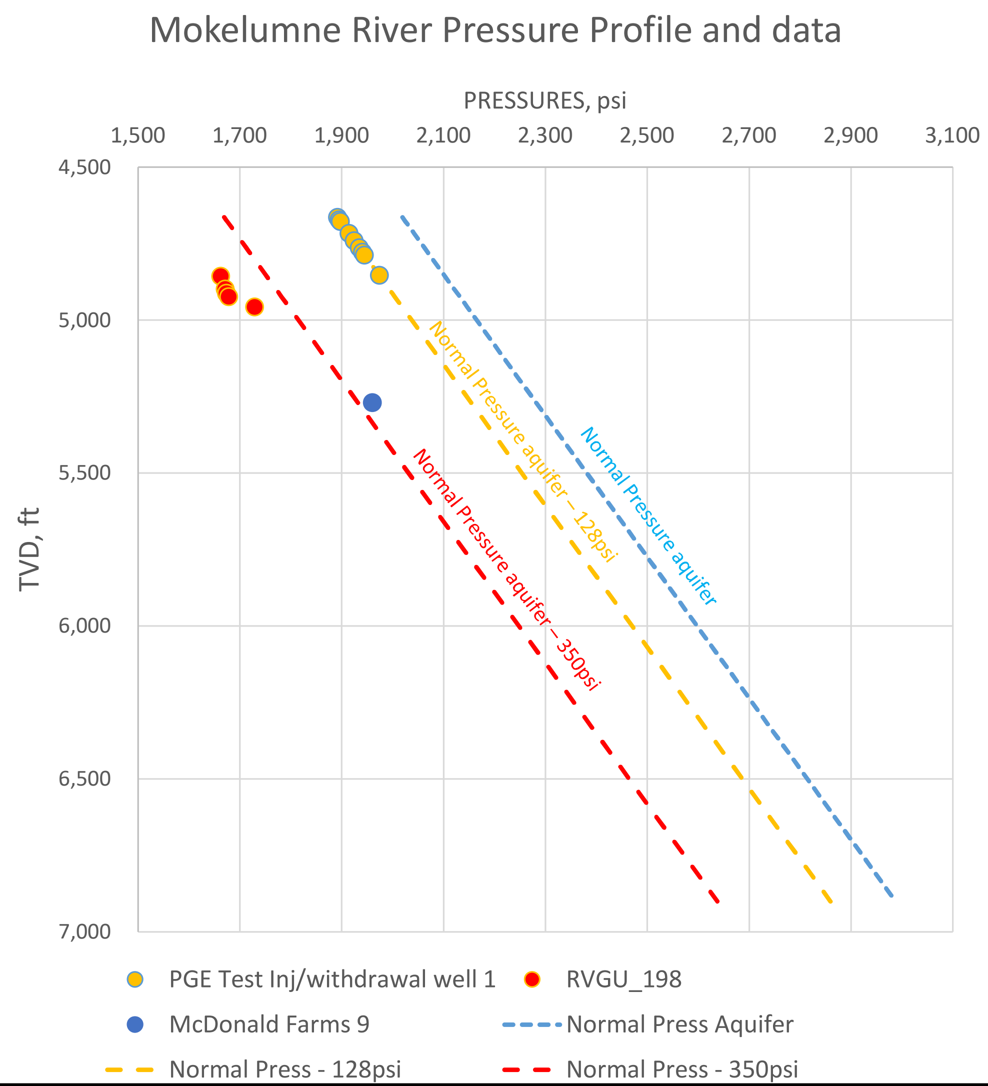


Figure 3.17 – Mokelumne River Formation pressure profile and data

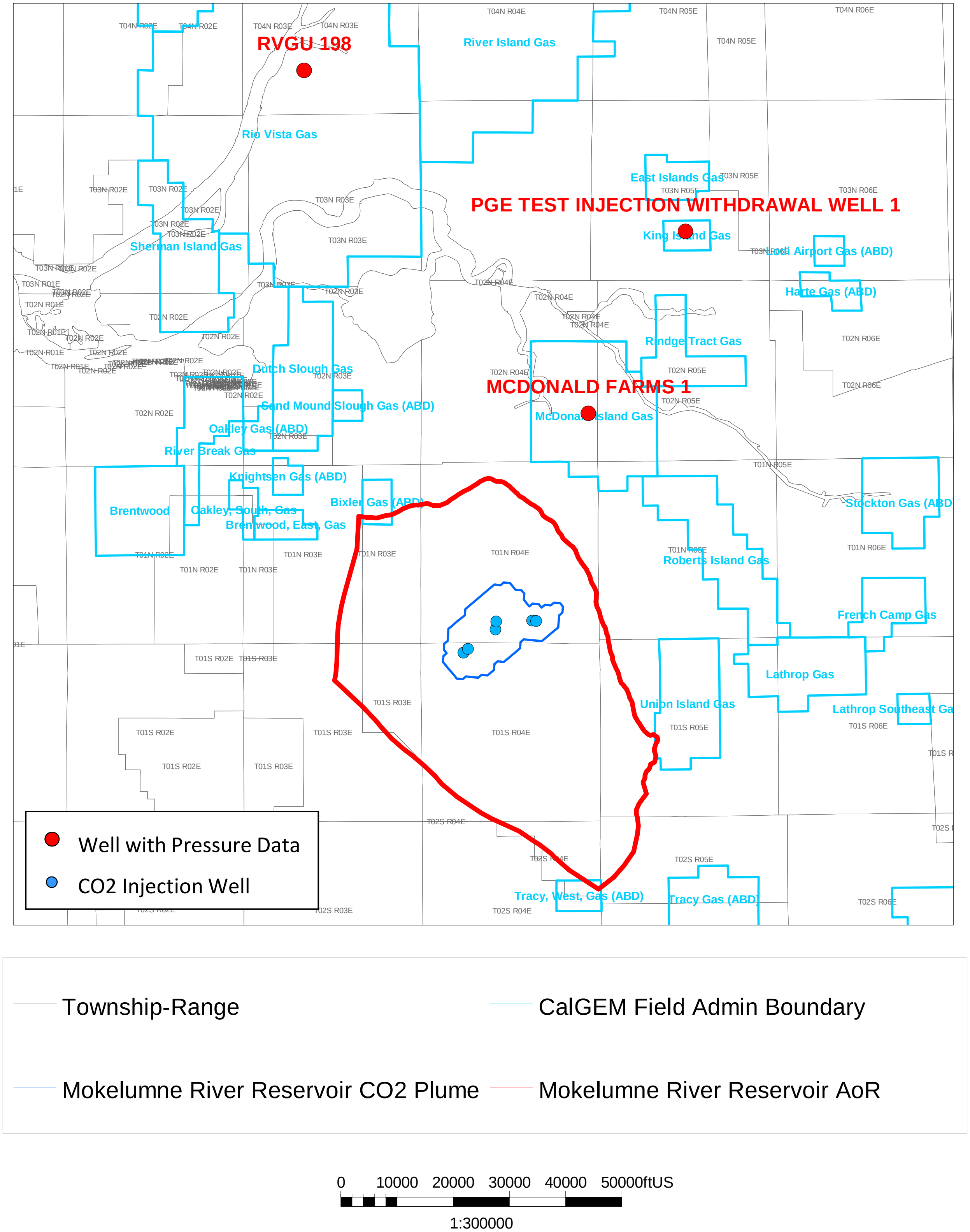


Figure 3.18. Map showing location of wells with pressure data for the Mokelumne River Formation.

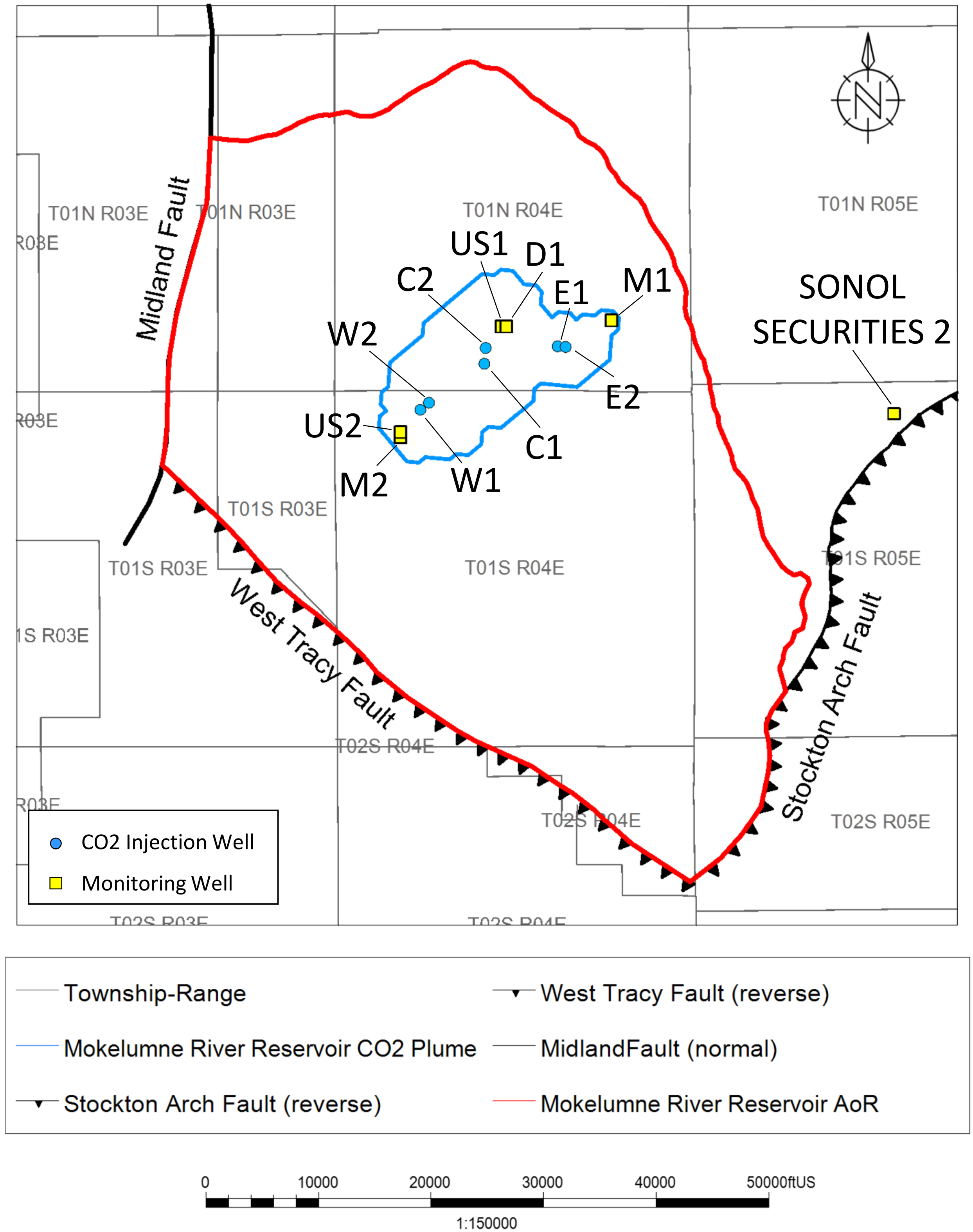


Figure 3.19. Map showing the location of injection wells and monitoring wells.

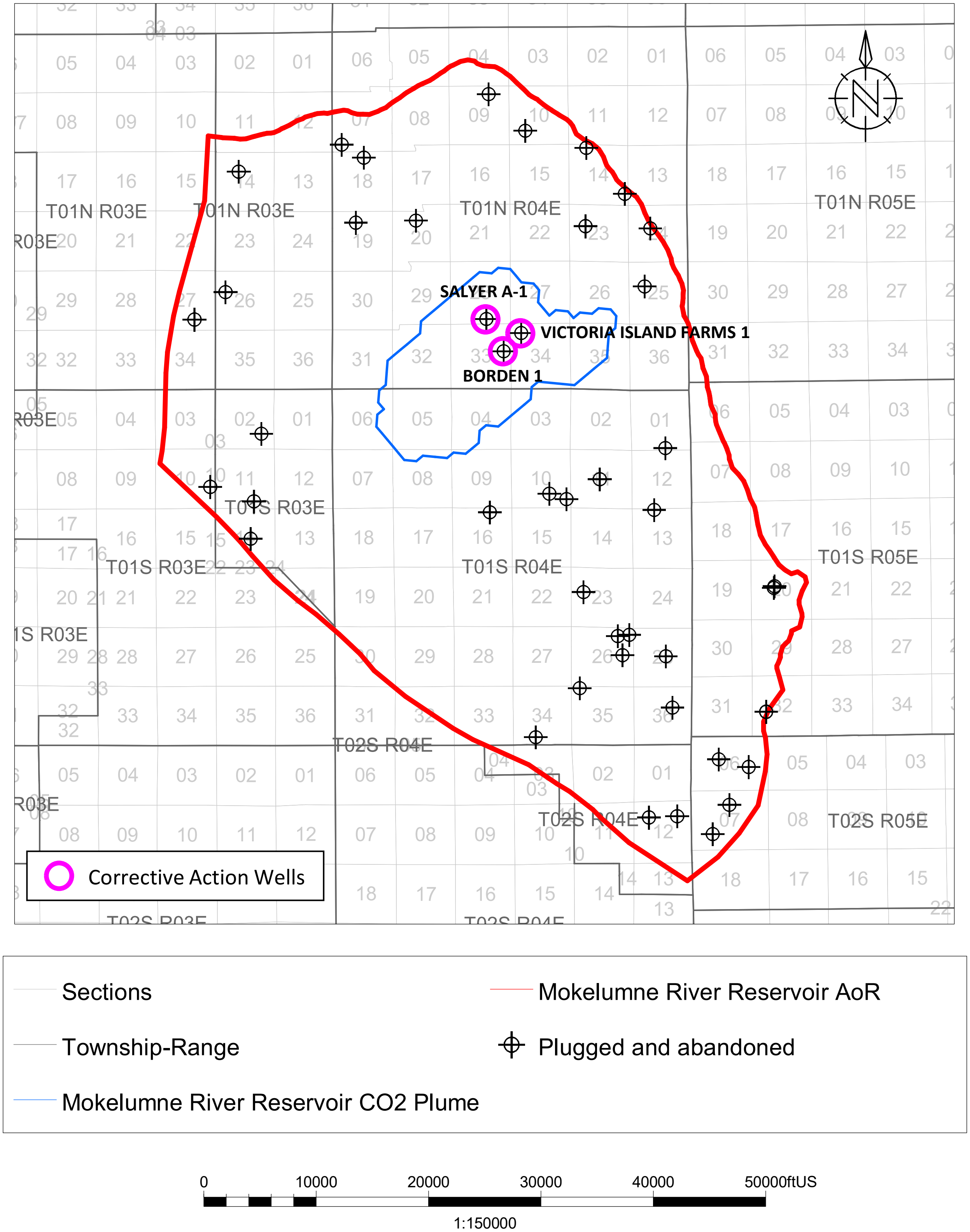


Figure 3.20. Wells penetrating the Capay Shale confining layer and Mokelumne River se questration reservoir reviewed for corrective action. Wells requiring corrective action p rior to injection are identified by magenta circles

AREA OF REVIEW AND CORRECTIVE ACTION PLAN - TABLES

Table 3.1. Model domain information.

Coordinate System	State Plane		
HorizontalDatum	North American Datum (NAD) 27		
Coordinate System Units	Feet		
Zone	Zone 2		
FIPSZONE	0402	**ADSZONE**	3301
Coordinate of X min	2,104,802.28	**Coordinate of X max**	2,181,962.01
Coordinate of Y min	35,524.40	**Coordinate of Y max**	135,851.00
Elevation of bottom of domain	-8,485.82	**Elevation of top of domain**	-4,534.97

Table 3.2. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	151	Fahrenheit	6900	Bottom hole temperature data from logs in the area
Formation pressure	2860	Pounds per square inch	6900	Downhole RFT data from PGE Test injection / Withdrawal well 1 adjusted to depth
Salinity	15,500	Parts per million	6900	Water analysis and Log calculated salinity curves

Table 3.3. Operating details.

Operating Information	Injection Well C1	Injection Well C2	Injection Well E1	Injection Well E2	Injection Well W1	Injection Well W2
Location (global coordinates)	37°53'18.0988"N 121°32'23.1187"W	37°53'32.0186"N 121°32'21.4924"W	37°53'33.1704"N 121°31'1.6409"W	37°53'32.5242"N 121°30'52.8591"W	37°52'37.6869"N 121°33'34.2543"W	37°52'44.0039"N 121°33'24.6627"W
Model coordinates (ft) X Y	2132846.72 81077.86	2132969.98 82486.69	2139371.35 82636.45	2140075.76 82574.83	2127163.01 76961.37	2127929.06 77604.16
No. of perforated intervals	11	5	14	6	7	8
Perforated interval (ft TVD) Top Bottom	6176 7016	7192 7790	6010 6950	6980 7720	6150 6930	7020 7840
Casing diameter (in.)	7	7	7	7	7	7
Modeled injection period Start End	01/01/2026 01/01/2054	01/01/2026 01/01/2054	01/01/2026 01/01/2036	01/01/2026 01/01/2040	01/01/2026 01/01/2031	01/01/2026 01/01/2042
Modeled Injection duration (years)	28	28	10	14	5	14
Modeled Injection rate (t/day)*	2754	2754	688	688	688	1377
Modeled CO_2 Injected (MMT)	28.2	28.2	2.5	3.5	1.3	7.0

Table 3.4. Injection pressure details.

Injection Pressure Details	Injection Well C1	Injection Well C2	Injection Well E1	Injection Well E2	Injection Well W1	Injection Well W2
Fracture gradient (psi/ft)	0.76	0.76	0.76	0.76	0.76	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4224	4919	4111	4774	4207	4802
Elevation corresponding to maximum injection pressure (ft TVD)	6178	7192	6011	6984	6155	7020
Elevation at the top of the perforated interval (ft TVD)	6178	7192	6011	6984	6155	7020
Calculated maximum injection pressure at the top of the perforated interval (psi)	4224	4919	4111	4774	4207	4802
Planned injection pressure (psi) / gradient (psi/ft) at top of perforations	3050 / 0.494	3566 / 0.496	2901 / 0.483	3363 / 0.482	2961 / 0.481	3504 / 0.499

Table 3.5. Simulation sensitivity scenarios

Scenario	CO2 plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

Table 3.6: Wellbores in the AoR by Status

Status	Count
Active	0
Idle	0
Plugged and Abandoned	46
Total	**46**