ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
[40 CFR 146.84(B)]
CTV III

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Document Version History

Version	Revision Date	File Name	Description of Change
1	5/03/2022	Attachment B – AoR_CA	Original submission
2	8/04/2022	Attachment B – AoR_CA V2	
3	11/30/2022	Attachment B - AoR_CA V3	
3.1	12/21/2022	Att B - AoR_CA CTV III V3.1	
4	5/24/2024	Att B – CTV III AOR_CA_V4_RtC	Response to February 20, 2024 EPA Comments
5	2/14/2025	Att B – CTV III AOR_CA_V5_RtC	Response to October 31, 2024 EPA Comments

Facility Information

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1. Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional (3D) representation of subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) and 3D 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.

1.1 Model Background

Computational modeling was completed using Computer Modeling Group's (CMG's) 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 carbon dioxide (CO_2) plume used 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:

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

- Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al.
- Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al.
- Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

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 to the north and west of the AoR; however, the reservoir sands are present across the entire AoR (**Figure B-1**). 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 project area.

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 approximately 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).

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 B-2**), define the subsurface geological characteristics of stratigraphy, lithology and rock properties.

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 B-1**.

A tartan grid with varying cell XY dimensions was rotated to an orientation of 40 degrees over the model domain, as shown in **Figure B-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 feet x 500 feet, but some cells are as small as 50 feet x 50 feet 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 1,000 feet x 1,000 feet cover the areas of the model that are farthest from the injectors.

As illustrated in **Figure B-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.

The open-hole logs have a 0.5-foot resolution and a constant vertical cell height of 20 feet was used over the model domain to generate grid layers as shown in **Figure B-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 B-5** shows a comparison of open-hole log data and the associated upscaled logs for a well near the AoR.

1.4 Porosity and Permeability

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

Formation porosity is determined one of two ways: from bulk density using 2.65 grams per cubic centimeter (g/cc) matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 microsecond per foot (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 uses capillary pressure porosity and permeability along with clay values from x-ray diffraction (XRD) or Fourier transformed infrared spectroscopy (FTIR). Core data from two wells with 13 data points was used to develop a permeability transform (**Figure B-6**). The transform from core data is illustrated in **Figure B-7**.

Figure B-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 B-9** shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model. The permeability in the vertical direction is approximated as $1/5^{th}$ of the horizontal permeability in the model and the modeled pore compressibility is 3.5×10^{-6}.

1.5 Constitutive Relationships and Other Rock Properties

As discussed in **Attachment A: Narrative**, Section 2.4.3, capillary pressure data were available for the Mokelumne River Formation (injection zone) from the Citizen_Green_1 well outside the project area in the King Island Gas Field. However, for computational modeling purposes, capillary pressure data obtained in the similar geologic age and setting Winters Formation in the nearby Union Island Gas field were used in addition to the Citizen_Green_1 data (**Figure B-2**). A sensitivity analysis (Case 11, Section 2.2.2) was run using only the Citizen_Green_1 capillary pressure data, but results indicated negligible changes to the AoR, CO_2 plume, and pressure field. The simulation and AoR will be updated once site specific core data is obtained during the pre-operational testing phase.

Figures B-10, B-11, and B-12 show the relative permeability curve, capillary pressure curve, and hysteretic gas-phase relative permeability plot used in the computational modeling.

1.6 Mineralization

Previous studies into reactive transport modeling and geochemical reaction in carbon capture and storage (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.

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 feet over the model domain has low permeability and 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 a Carter Tracy numerical aquifer, with the properties defined in Case 1 of **Table B-5**.

1.8 Initial Conditions

Initial model conditions (start of CO_2 injection) of the Mokelumne River Formation are given in **Table B-2**. The temperature is set as variable with depth using a gradient of 0.013°F, approximated from logging run bottom hole temperature data (**Figure B-13**) and an initial pressure was determined to be hydrostatic less 128 pounds per square inch (psi), which is obtained as repeat formation test (RFT) pressure data from an analog PGE test injection well (**Figures B-14 and B-15**). The pressure is defined at a datum depth, from which the reservoir simulation software equilibrates pressure for the model. A Salinity of 15,500 PPM was used and approximated from water analysis as discussed in Section 2.8.2 of **Attachment A**.

1.9 Operational Information

Details on the injection operation are presented in **Table B-3**. The anticipated injection temperature at the wellhead is 90°F to 130°F. Further details are provided in **Attachment A** and in **Appendix 4: Operational Procedures**.

1.10 Fracture Pressure and Fracture Gradient

Calculated fracture gradient and target injection pressure values are given in **Table B-4**.

A fracture pressure gradient of 0.76 pounds per square inch per foot (psi/ft) is assumed for the injection zone. This is based on formation integrity tests in the Mokelumne River Formation conducted on wells Yamada_LW_1 and 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 mini-frac 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 B-4**). CTV expects to operate the wells with a planned bottomhole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

All proposed injection wells are constant-rate controlled subject to a maximum allowable injection pressure that is based on fracture gradient plus a 90% safety factor. Each injector's BHP is shown in **Figure B-16**. Reservoir pressures near each injector, calculated using the five-points method, are shown in **Figure B-17**. The five-points method uses the pore-volume weighted average pressure of the block containing the bottomhole of the well as well as the four neighboring blocks.

2. Computational Modeling Results

2.1 Predictions of System Behavior

Figures B-18 and B-19 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. **Figure B-19** displays the maximum plume area with depth at various time steps through the project.

As shown in **Figure B-18**, 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 B-20** shows the cumulative storage for each of the mechanisms. CO_2 plume area pressure through time is shown in **Figure B-21**. Initial, peak, and delta reservoir pressure across the project area is shown in **Figure B-22.** **Figure B-23** displays CO_2 saturation in cross section view through time at each injection well.

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 (Foxall, et. al., 2017; Doughty and Oldenburg, 2011; Beyer et al., 2013). The results of CTV's simulation compare favorably against the previous work by LBNL regarding storage capacity and CO_2 plume size.

2.2.1 CO_2 Injectate Effect on Plume and AoR Modeling Results

The plume model developed in the CMG GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO_2 injectate case. The cumulative volume of injectate for all three cases was the same.

The CO_2 plume for Injectate 1 and Injectate 2 is consistent with the plume outline for 100% CO_2 injectate (**Figure B-24**), which was defined by a 0.01 global CO_2 mole fraction for all three cases. The 100-year post end of injection plumes for the three cases are shown in **Figure B-24**. The wells that fall within the CO_2 plume are the same for all three cases.

Similarly, the AoR was delineated using a risk based approach for the three cases and was found to be consistent. Details on the risk based approach method are discussed in Section 3 of this attachment. **Figure B-24** shows the AoR boundary for the three cases. Additionally, the average pore volume pressure within the approximate AoR boundary was plotted for the three cases and was found to be very close, with a maximum difference of approximately 5 psi seen between the cases, as shown in **Figure B-25**. Multiple scenarios were also run to test the effect of mixing Injectate 1 and Injectate 2 in different ratios on the AoR boundary and plume shapes. As expected, because the resulting mixed injectates were still high-purity CO_2 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 of Injectates 1 and 2.

In summary, there is minimal effect of the minor components on the CO_2 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 per the Reevaluation Schedule and Criteria section.

2.2.2 Sensitivity Cases

The reference base case is considered a sufficiently realistic representation of the hydrogeologic structure and conditions at the proposed injection site suitable for delineating the AoR. Sensitivity analyses were performed to examine the impacts of various assumptions on the simulation results. Sensitivity scenarios listed in **Table B-5** were run varying major inputs to the simulation to see whether they have any significant impact on the CO_2 plume boundary (**Figure B-26**) or CO_2 plume area volumetric pressure (**Figure B-27**). Bottomhole pressure plots for sensitivity Case 10 are shown in **Figure B-28**. None of the cases show significant variability from the reference Case 1 for the plume boundary. . The interference case was modeled independently with combined injection from CTV III, CTV V and Pelican Renewables, with simultaneous injection from all projects.

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. AoR Delineation

AoR delineation consists of determining the outermost extent of the separate-phase CO_2 plume and area of elevated pressure (pressure front) that pose risk to USDWs during the lifetime of the project. Elevated pressure may pose a risk to USDWs due to the potential for brine leakage from the injection zone into a USDW through a conduit if one is present (e.g., improperly abandoned well). In most cases the AoR will at a minimum be defined by the CO_2 plume footprint and may be larger if the pressure front extends beyond the CO_2 plume. CTV III used the risk based AOR approach as documented in **Appendix B-4**.

Various methods are available to determine the pressure threshold value that defines the outermost extent of the pressure front. In general, these methods are used to define a pressure at which brine will leak upwards through an abandoned well, leak into a USDW, and endanger the USDW due to water quality impairment. Risk-based AoR delineation accounts for processes that inhibit brine leakage through abandoned wells (e.g., presence of the mud column) and processes that minimize potential USDW impacts from hypothetical brine leakage (e.g., dilution and attenuation in the USDW). Risk-based AoR delineation strategies are supported by the U.S. EPA (2013) Class VI AoR and Corrective Action Guidance (p. 42).

Appendix B-4: Risk-Based AoR Reports includes a description on the evolution of the risk-based AoR method (Report 1) and two additional reports that document risk-based AoR delineation at CTV III. The risk-based AoR delineation consisted of (1) modeling brine leakage under conservative assumptions and resulting salinity impacts to the lowermost USDW (Report 2 in **Appendix B-4**) and (2) review of wellbore properties in the vicinity of the project and allowable pressure buildup considering the presence of the mud column (Report 3 in **Appendix B-4**). As requested by EPA and by use of provided guidelines, CTV evaluated the critical pressure boundary using Method 1 from EPA's UIC Class VI Well AoR Evaluation and Corrective Action Guidance. The resultant critical pressure front boundary is displayed in Figure 1 of Report 1 in **Appendix B-4**).

Brine-leakage and USDW salinity transport modeling (Report 2 in **Appendix B-4**) used conservative assumptions and accepted methods to simulate (1) brine leakage through an abandoned well and (2) subsequent contaminant fate and transport within the lowermost USDW. Modeling indicated that the vast majority of brine leakage through a hypothetical abandoned well in the vicinity of the project would discharge to the Domengine dissipation zone (below the lowermost UDSW), and therefore brine leakage to the USDW would be negligible. Concomitantly, elevated salinity levels in the lowermost USDW are calculated to be negligible. These results were based on an assumed injection-zone pressure increase of 525 psi. CMG-GEM modeling results indicate that pressure increase of this magnitude will not occur outside the boundary of the CO_2 plume for both a case considering the CTV III project alone, and an interference simulation case (**Appendix B-4**, Figures 3a & 3b) considering the combined pressure increase from the planned CTV III, CTV V (King Island), and Pelican Renewables projects.

Irani Engineering (see Report 3 in **Appendix B-4**) has 39 years of experience drilling and completing gas wells in northern California (over 1,000 wells drilled), including reentering five old abandoned wells to assess mud properties. Based on this experience, existing research papers, and third-party reports of reentry into old abandoned wells, they conclude that the modeled pressure increase in the injection zone at the well penetrations in the CTV III project region is not sufficient to induce vertical migration of fluid from the injection zone to the base of the USDW. Specifically, the positive pressure provided by the mud column in the wellbores is well above the modeled pressure increase at these locations due to CO_2 injection. The gel strength of the mud also provides an additional resistance to fluid migration. Gel-based muds used in these abandoned uncased wellbores in the vicinity of CTV III remain in the wellbore, and thus provide resistance to the migration of fluids and will prevent any USDW contamination.

Based on these results pressures high enough to endanger USDWs are not anticipated outside the CO_2 plume footprint, and the final AoR boundary was based on the extent of the CO_2 plume. **Figure B-29** shows the AoR extent, injector locations, and proposed monitoring well locations. Details on the monitoring wells are discussed further in **Attachment C: Testing and Monitoring Plan**.

Any additional CO_2 injection subsurface storage operations in the area will impact the project AOR and may increase the risk to USDWs.

4. Corrective Action

4.1 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 B-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 and pressure front boundary. 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 and requirement for corrective action, if necessary. CTV also identifies well work to be completed during the pre-operational testing phase. Wells reviewed for corrective action are shown in **Figure B-30**.

4.2 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.

4.3 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.

4.4 Mokelumne River Formation Isolation

All 3 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. Additionally, CTV plans to obtain approval from a few landowners with water wells in the vicinity of the AoR for added monitoring of USDW by collecting frequent samples as described in Table 5 of **Attachment C**.

4.5 Corrective Action Assessment of Wells in AoR

Three wells located within the CO_2 plume, shown in **Figure B-30**, 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 reenter these three wells, drill out the plugs, and replug 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. **Appendix B-3** shows diagrams for the current well configuration and proposed corrective action.

For the wells in the AoR, CTV will provide a strategy and/or corrective action plan on these wells during pre-operational testing. A map with these wells is shown in **Figure B-30**, and the table of wells in **Appendix B-1** provides well information pursuant to 40 CFR §146.84(c)(2).

4.6 Plan for Site Access

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

4.7 Corrective Action Schedule

Corrective action will be completed on the 3 wells within the CO_2 plume prior to injection. CTV will ensure that CO_2 is confined to the injection zone within the AoR, protecting the overlying USDW and ensuring confinement. CTV will communicate a specific corrective action schedule to EPA prior to permit finalization.

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.

5. Reevaluation Schedule and Criteria

5.1 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. These 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).

Reevaluation 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 reevaluation 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.

5.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

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

- Changes in pressure or injection rate that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.
- Difference between the computation modeling and observed plume development:
  - Unexpected changes in fluid constituents or pressure outside the Mokelumne River Formation reservoir that are not related to well integrity.
  - Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.
  - Any other activity prompting a model recalibration.
- Seismic monitoring anomalies within 2 miles of the injection well that are indicative of:
  - The presence of faults near the confining zone that indicates propagation into the confining zone.
  - Events reasonably associated with CO_2 injection that are greater than M3.5.
- Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.
- 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).
- 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).
- A significant change in injection operations, as measured by wellhead monitoring.
- Significant land-use changes that would impact site access.
- 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 reevaluation is required. If an unscheduled reevaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.

6. References

Beyer J.H., J.A. Franklin, E. Burton et. al., “Geologic characterization based on deep core and fluid samples from the Sacramento Basin of California—an Update,” Presented at West Coast Regional Carbon Sequestration Partnership, May 2013.

Doughty C., C. Oldenburg, “Preliminary TOUGH2 Model of King Island CO_2 Injection,” Presented at West Coast Regional Carbon Sequestration Partnership, October 25, 2011.

Foxall W., C. Doughty, K. J. Lee et al., 2017, "Investigation of Potential Induced Seismicity related to Geologic Carbon Dioxide Sequestration in California,” CEC-500-2017-028.

Figures

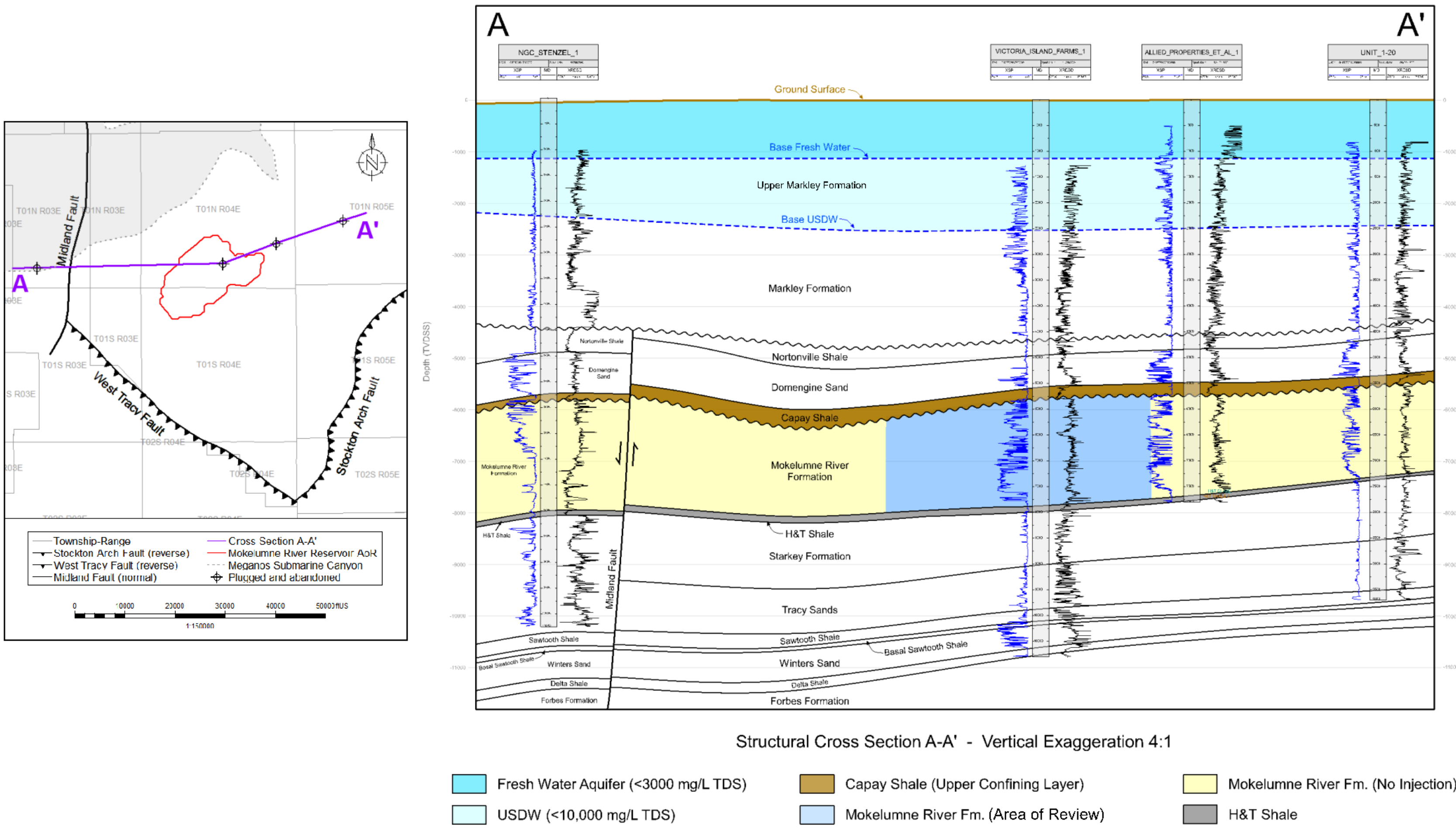


Figure B-1. Cross section showing stratigraphy and lateral continuity of major formations across the project area.

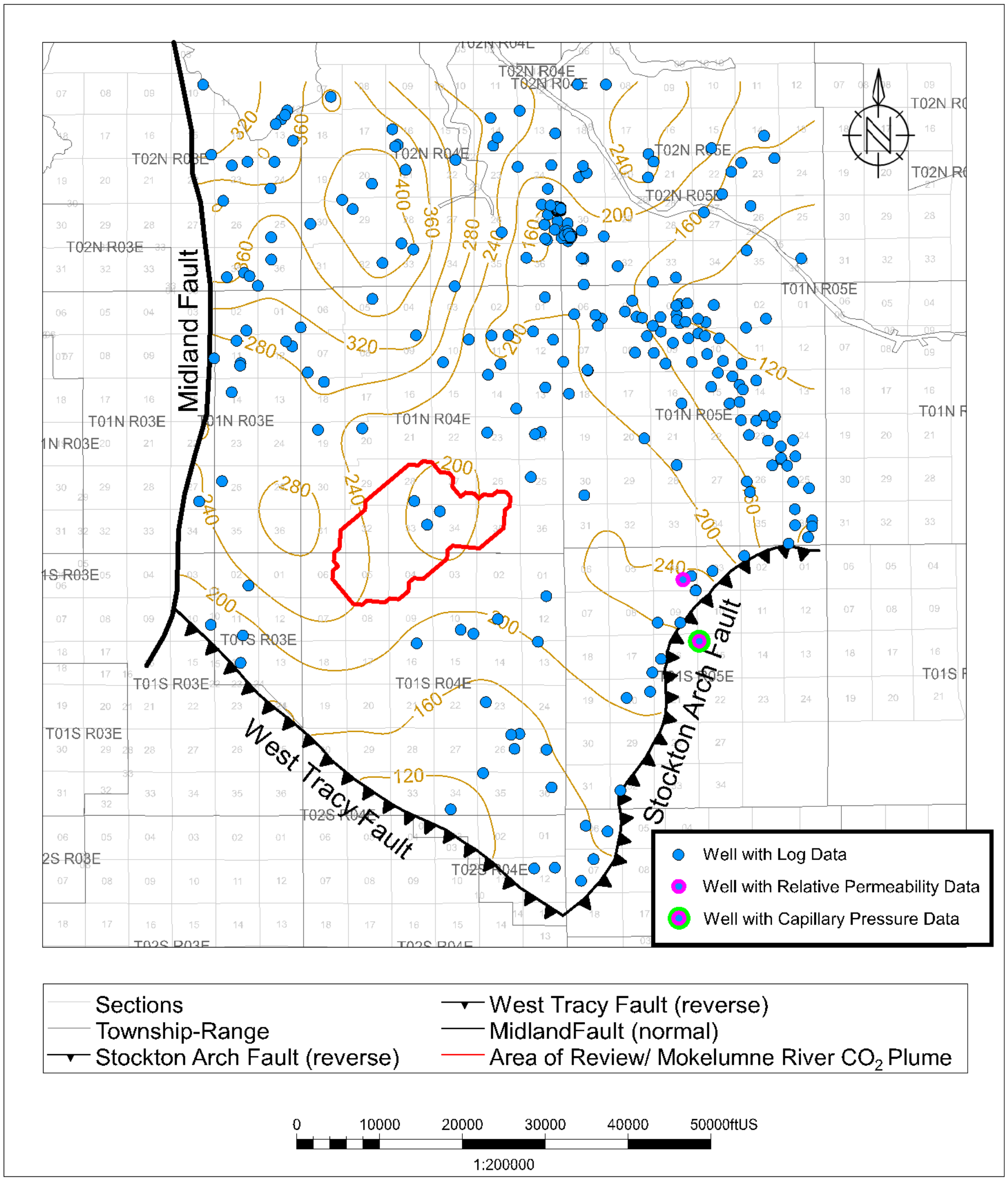


Figure B-2. Locations of wells with open-hole log data and Winters zone relative permeability or capillary pressure data used to develop the static and computational models.

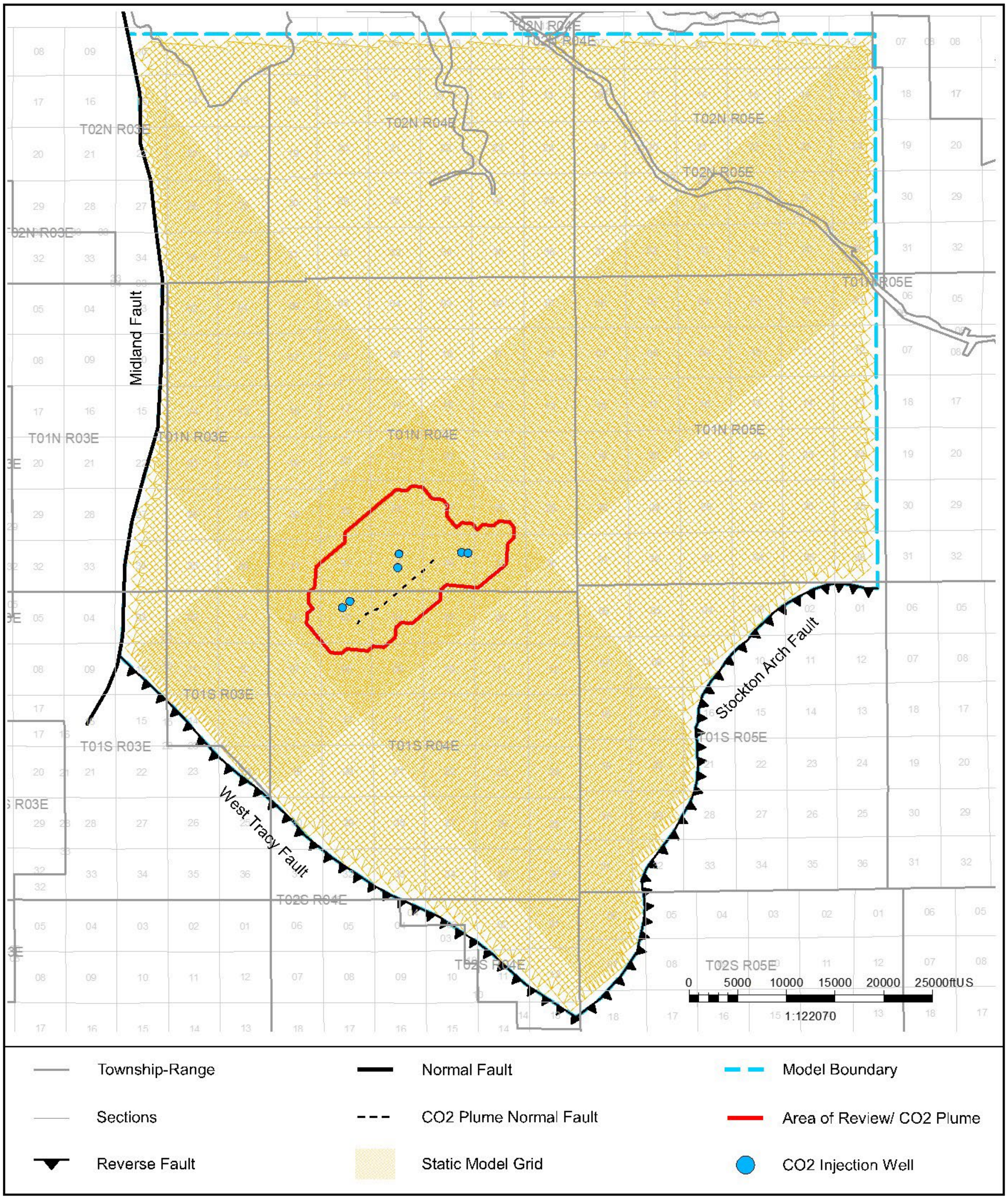


Figure B-3. Plan view of the model boundary and geo-cellular grid used to define the AoR.

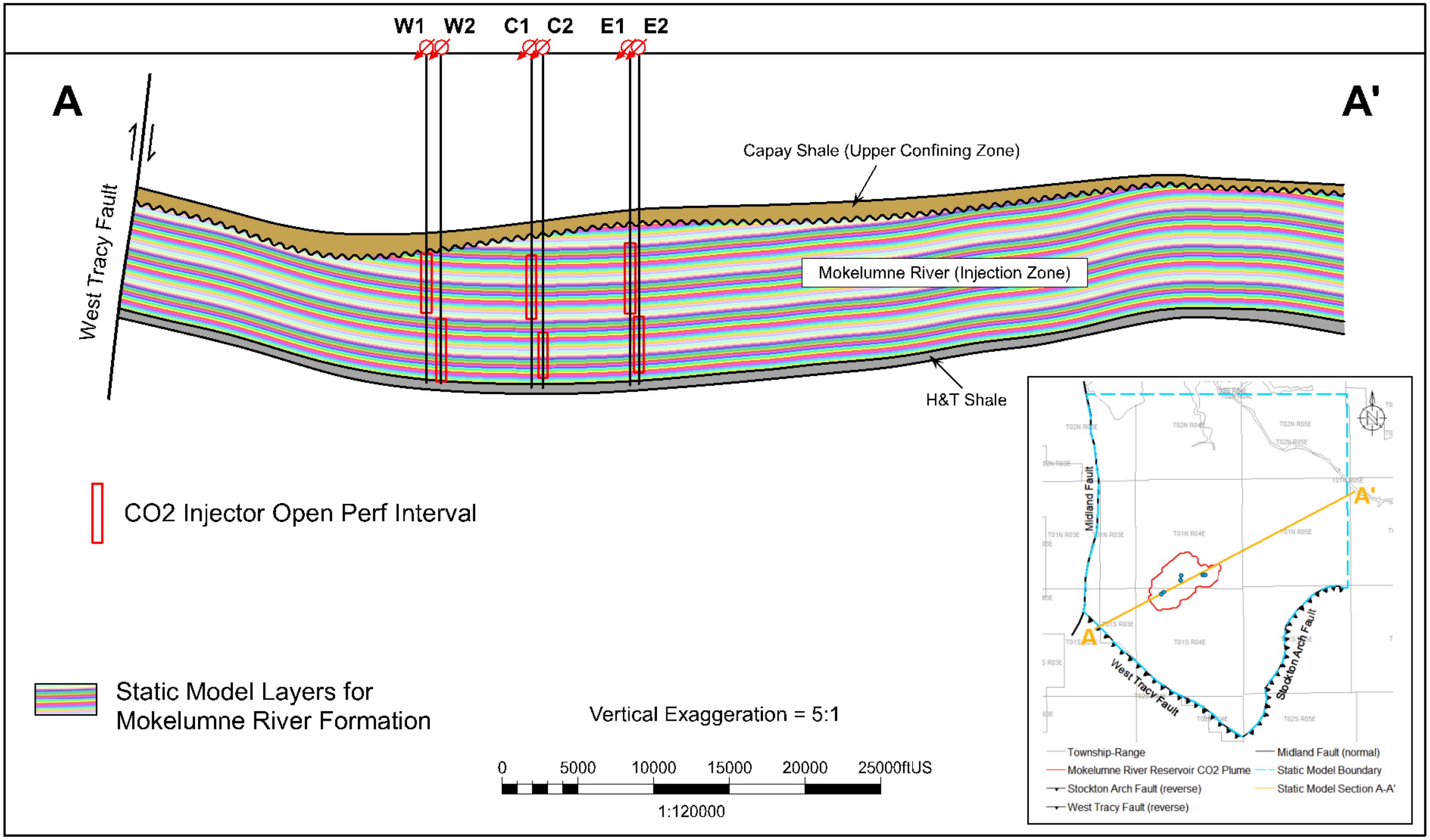


Figure B-4. **Static model grid layering of the Mokelumne River Formation. Stratigraphic units are bound to the west, southwest, and southeast by the Midland, West Tracy, and Stockton Arch Faults, respectively.**

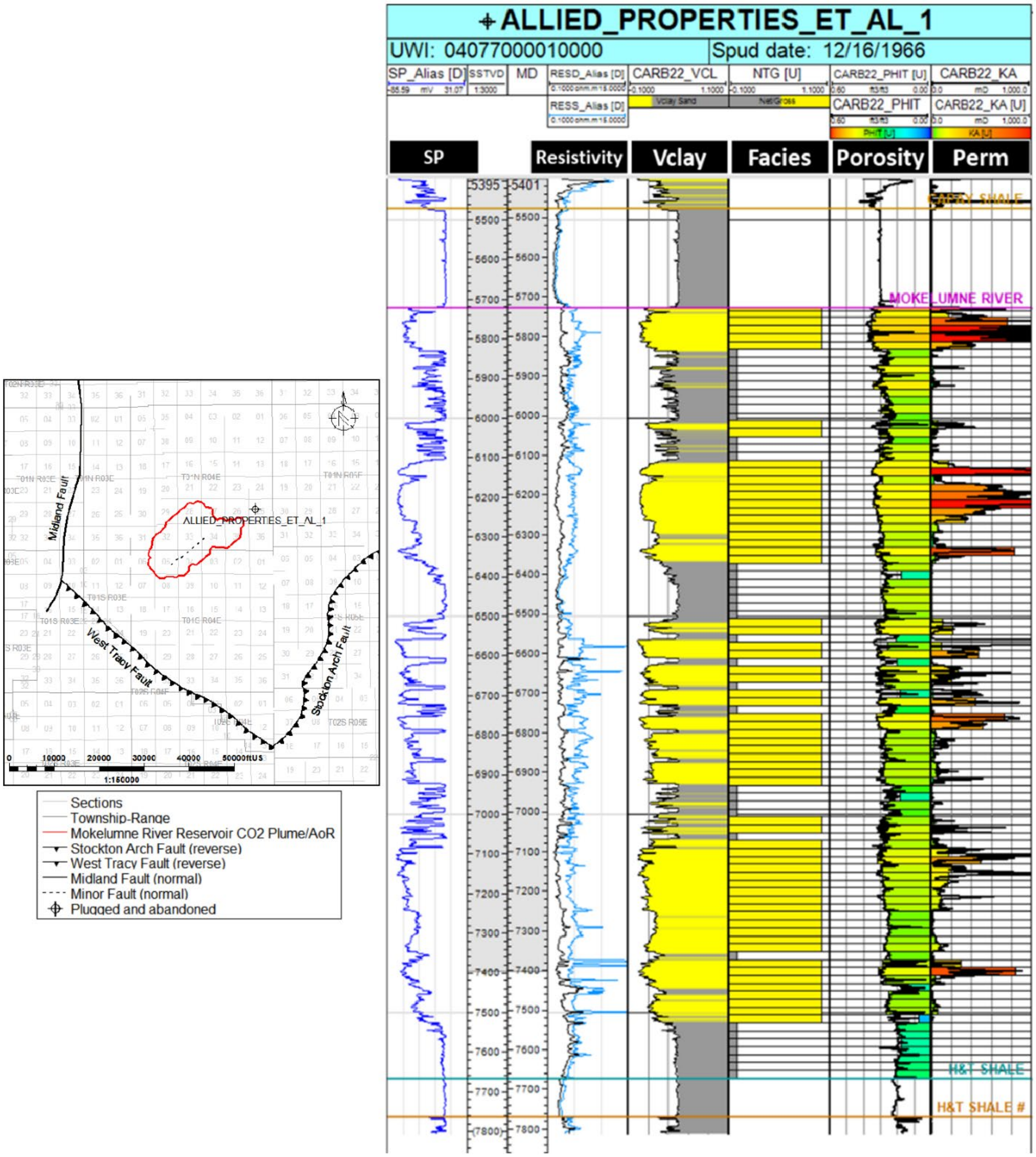


Figure B-5. Well "Allied Properties Et Al 1" upscaled logs versus open-hole logs.

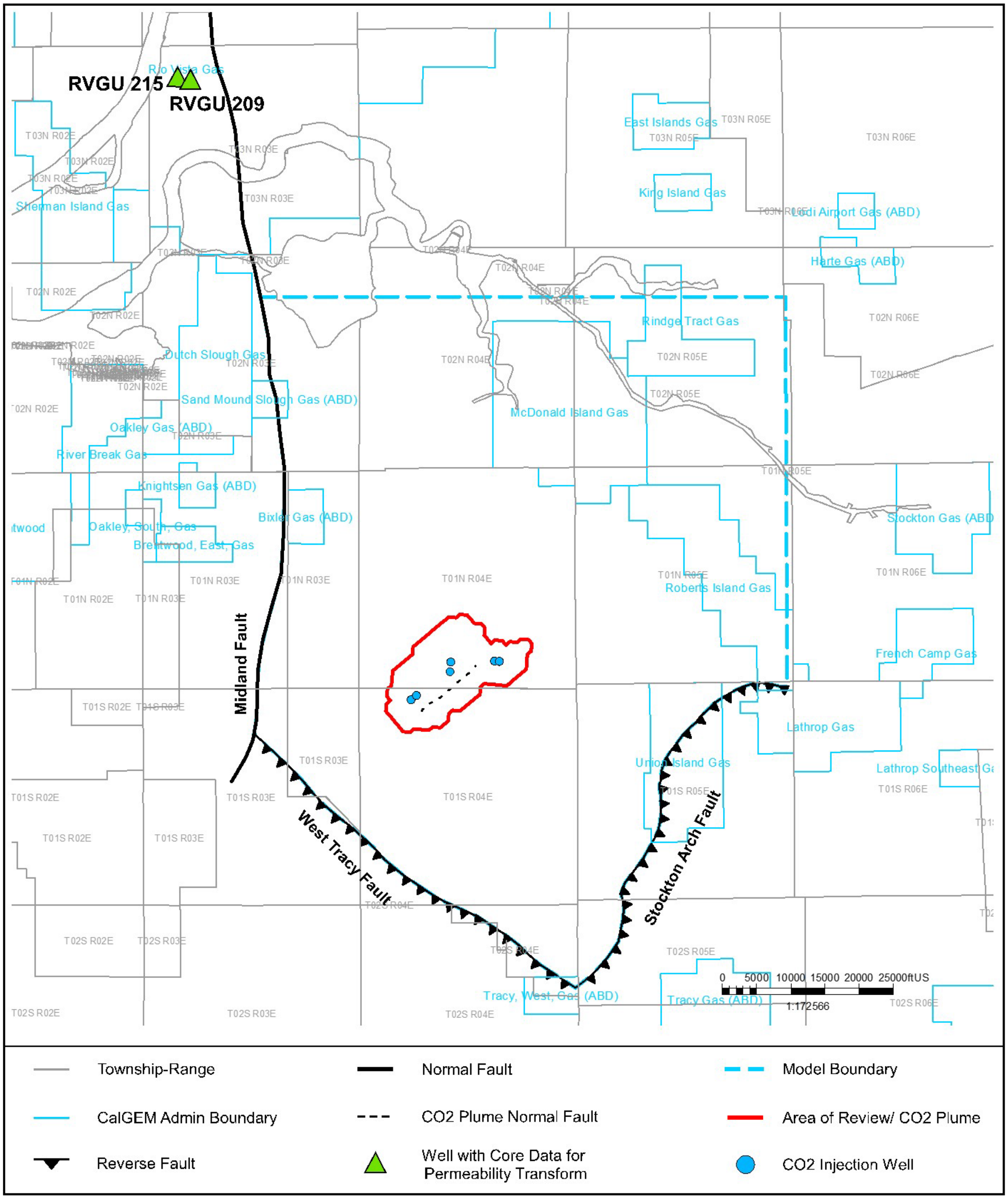


Figure B-6. Locations of wells with core data used for permeability transform.

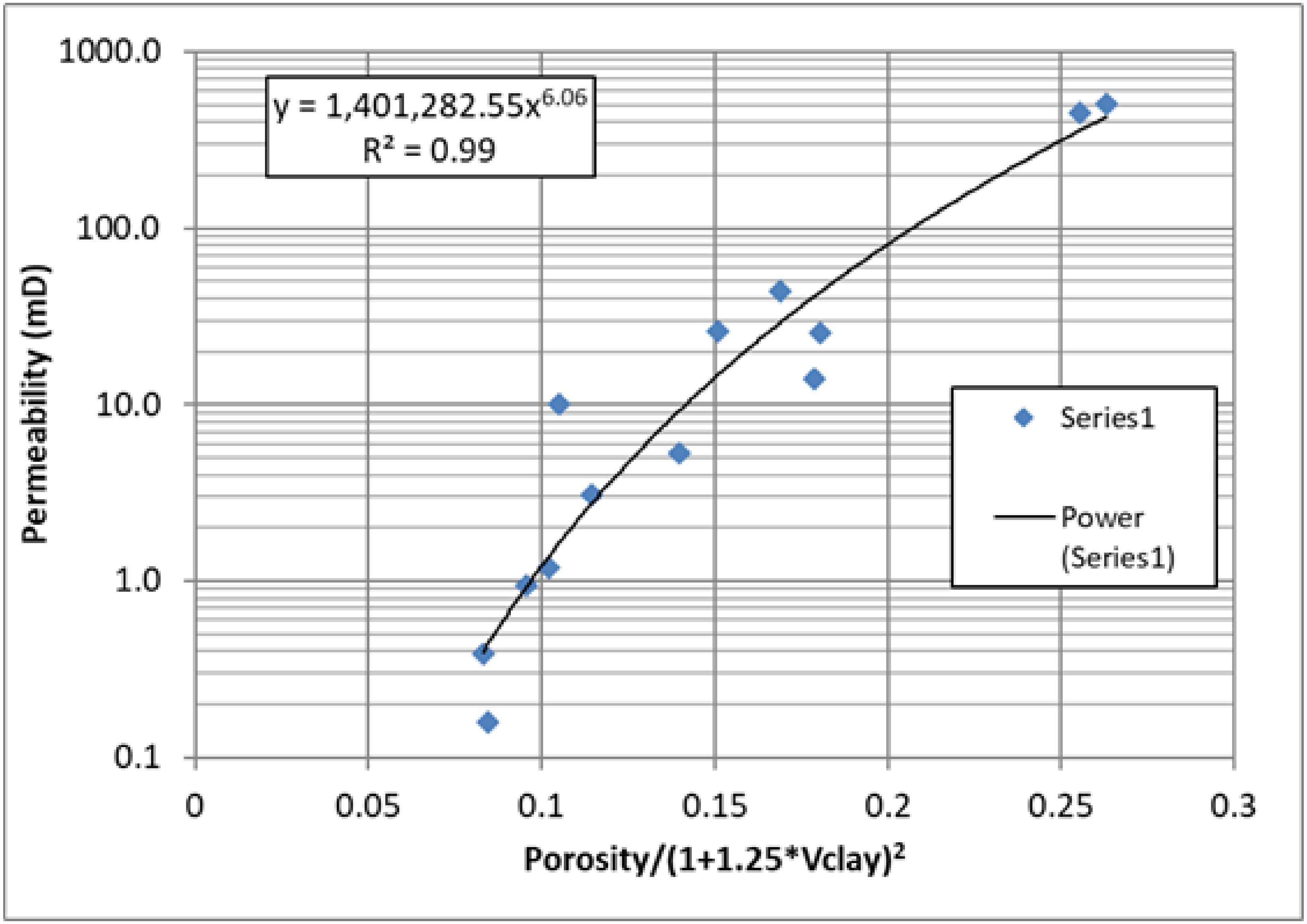


Figure B-7. Permeability transform for Sacramento Basin zones.

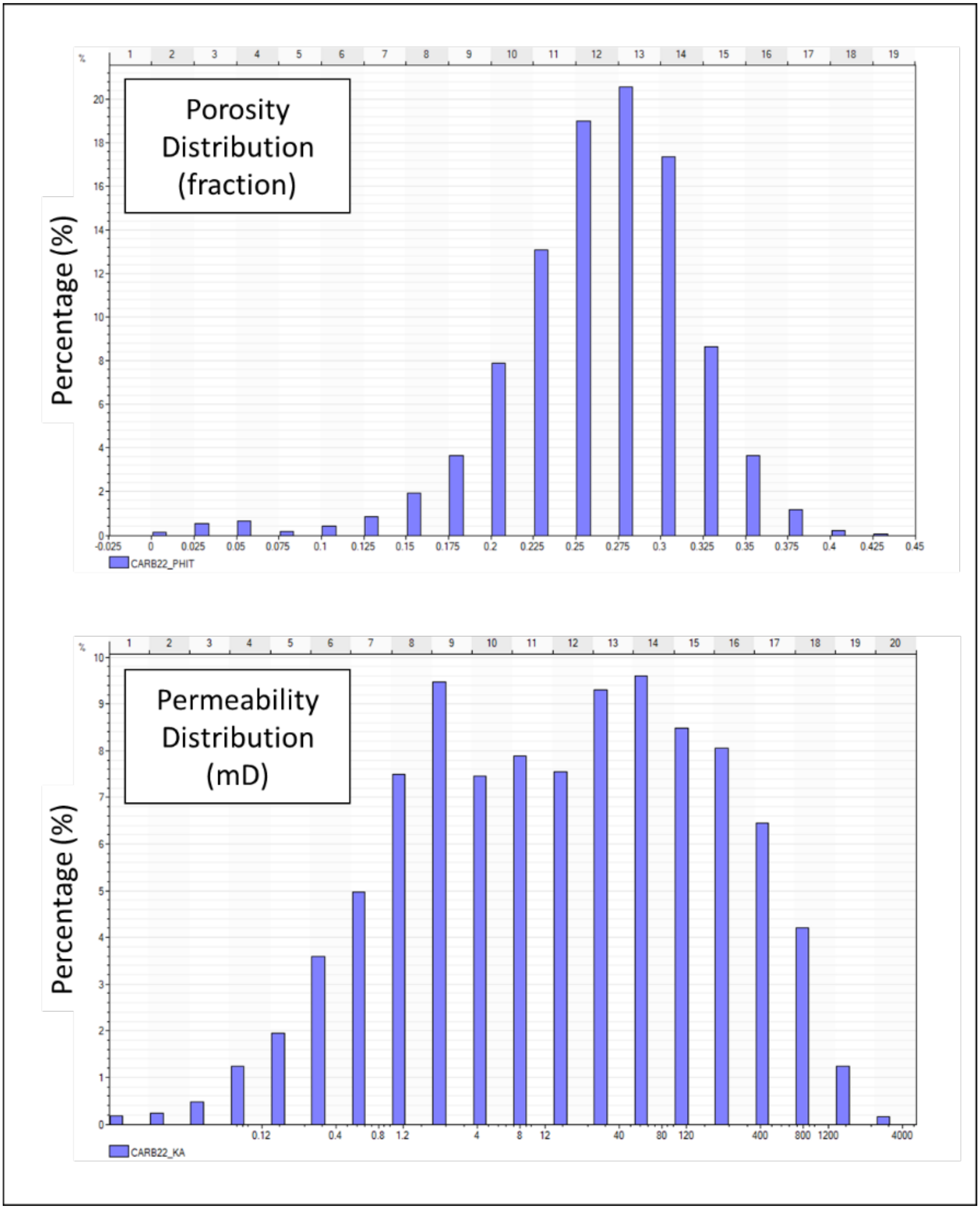
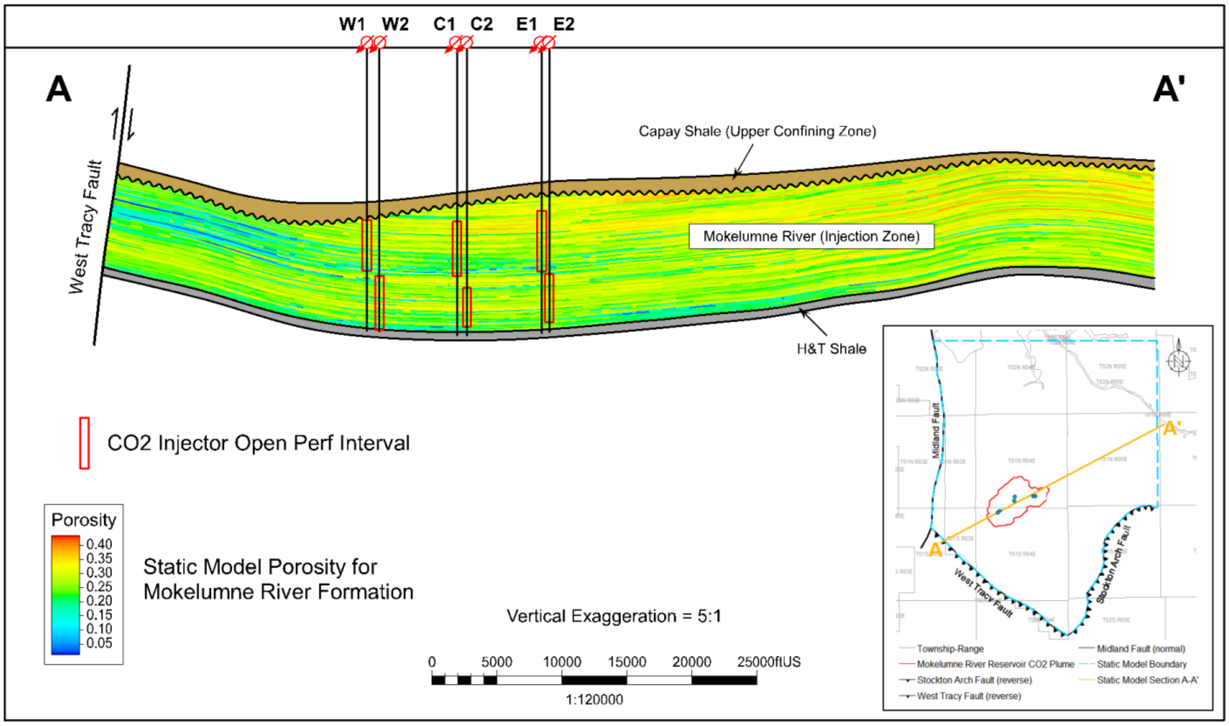


Figure B-8. Mokelumne River Formation porosity and permeability distribution in the static model.



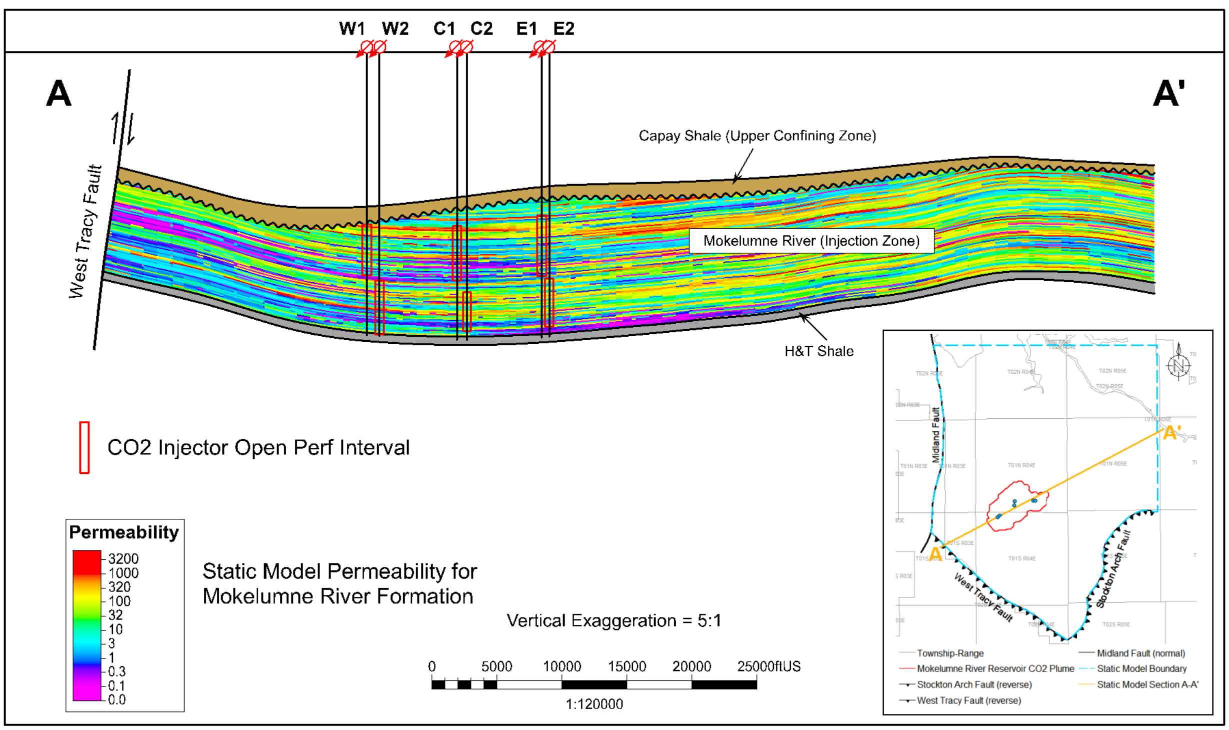


Figure B-9. Sections through the static grid showing the distribution of porosity and permeability in the reservoir.

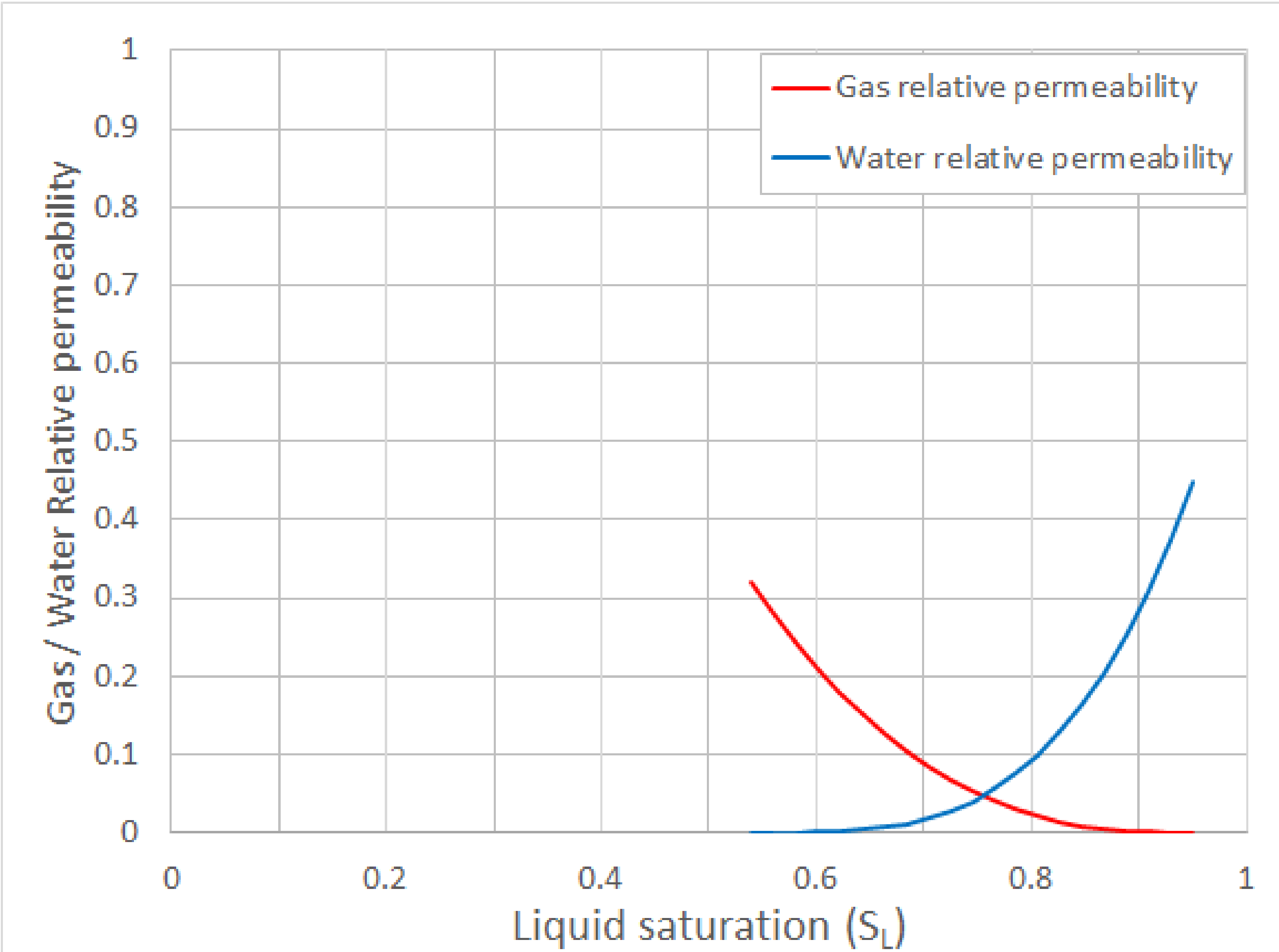


Figure B-10. Relative permeability curves for gas-water system.

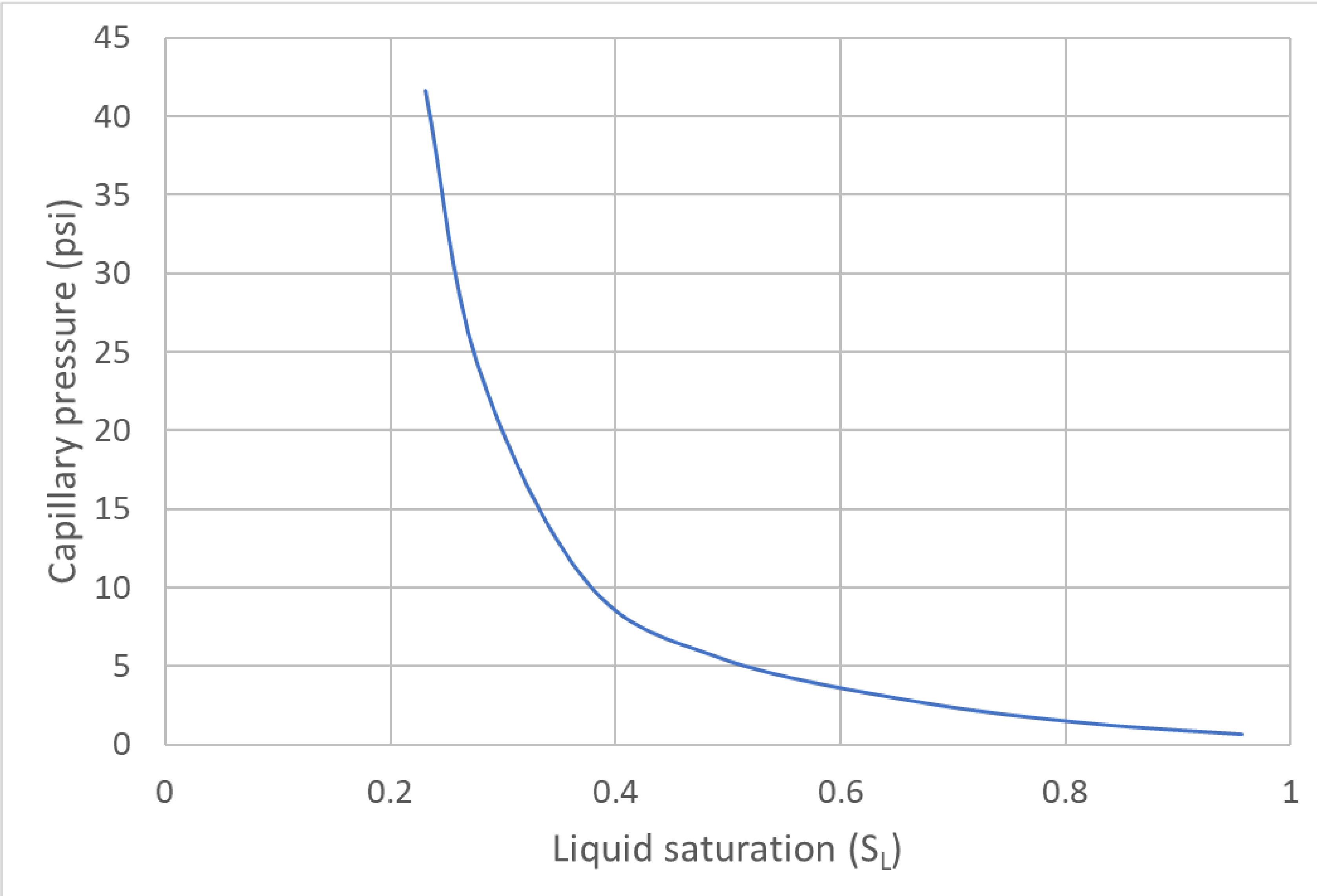


Figure B-11. Capillary pressure curve.

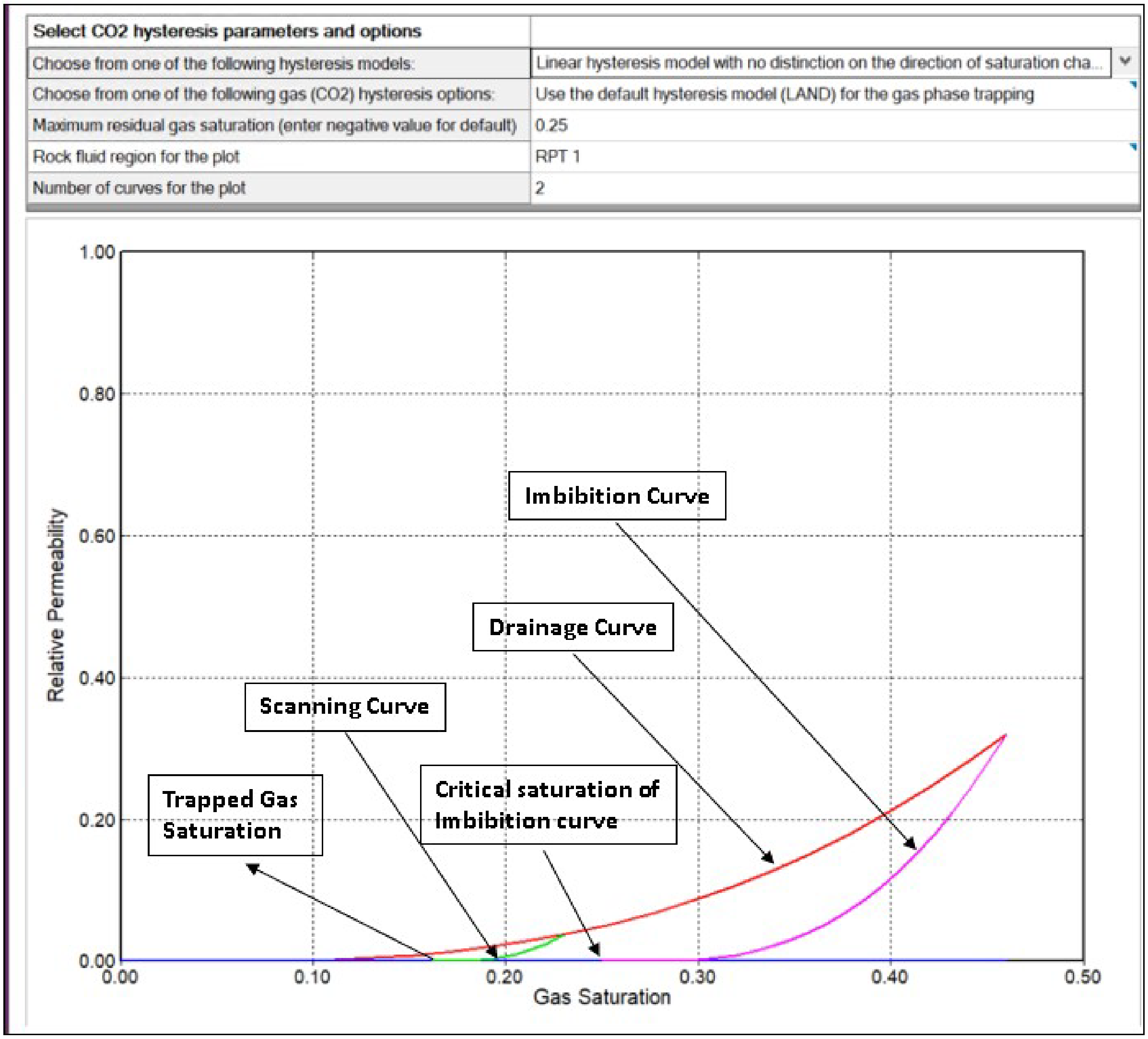


Figure B-12. Hysteretic gas-phase relative permeability plot.

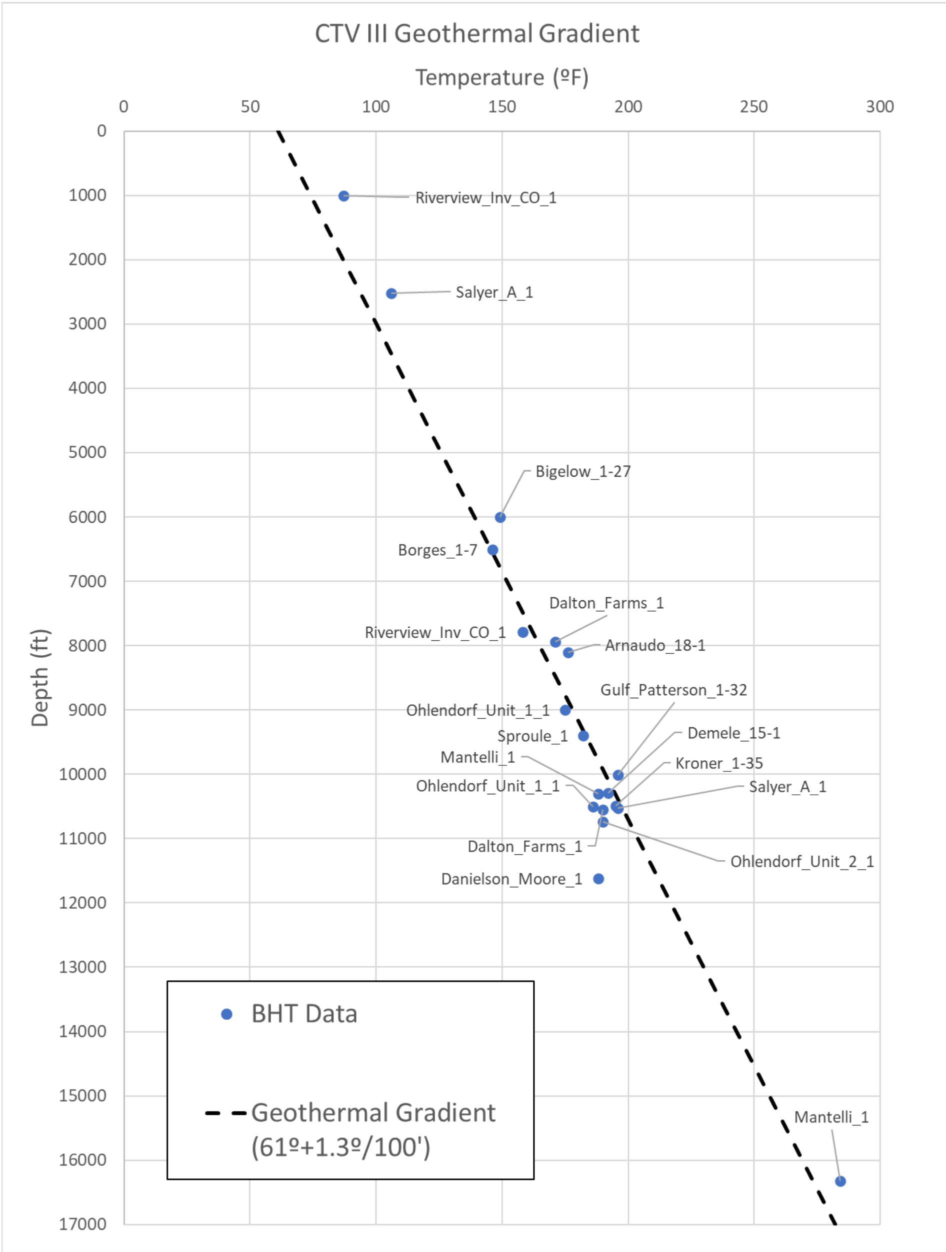


Figure B-13. Bottomhole temperature (BHT) data from wells in the project vicinity. The data are from individual logging runs and may include multiple BHT datapoints from the same well due to different logging runs. The geothermal gradient of 1.3ºF/100' is overlain to show the match to the observed data.

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

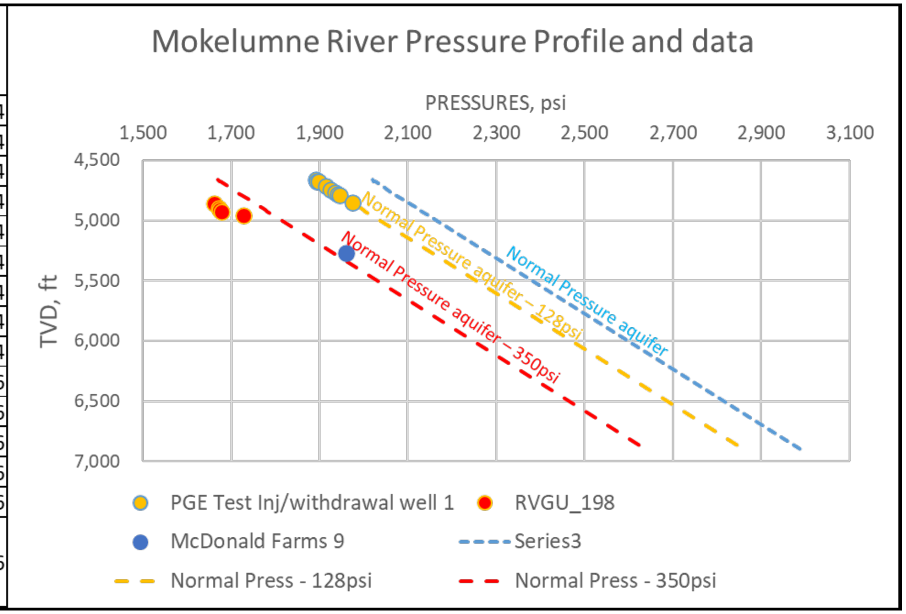


Figure B-14. Mokelumne River Formation pressure profile and data.

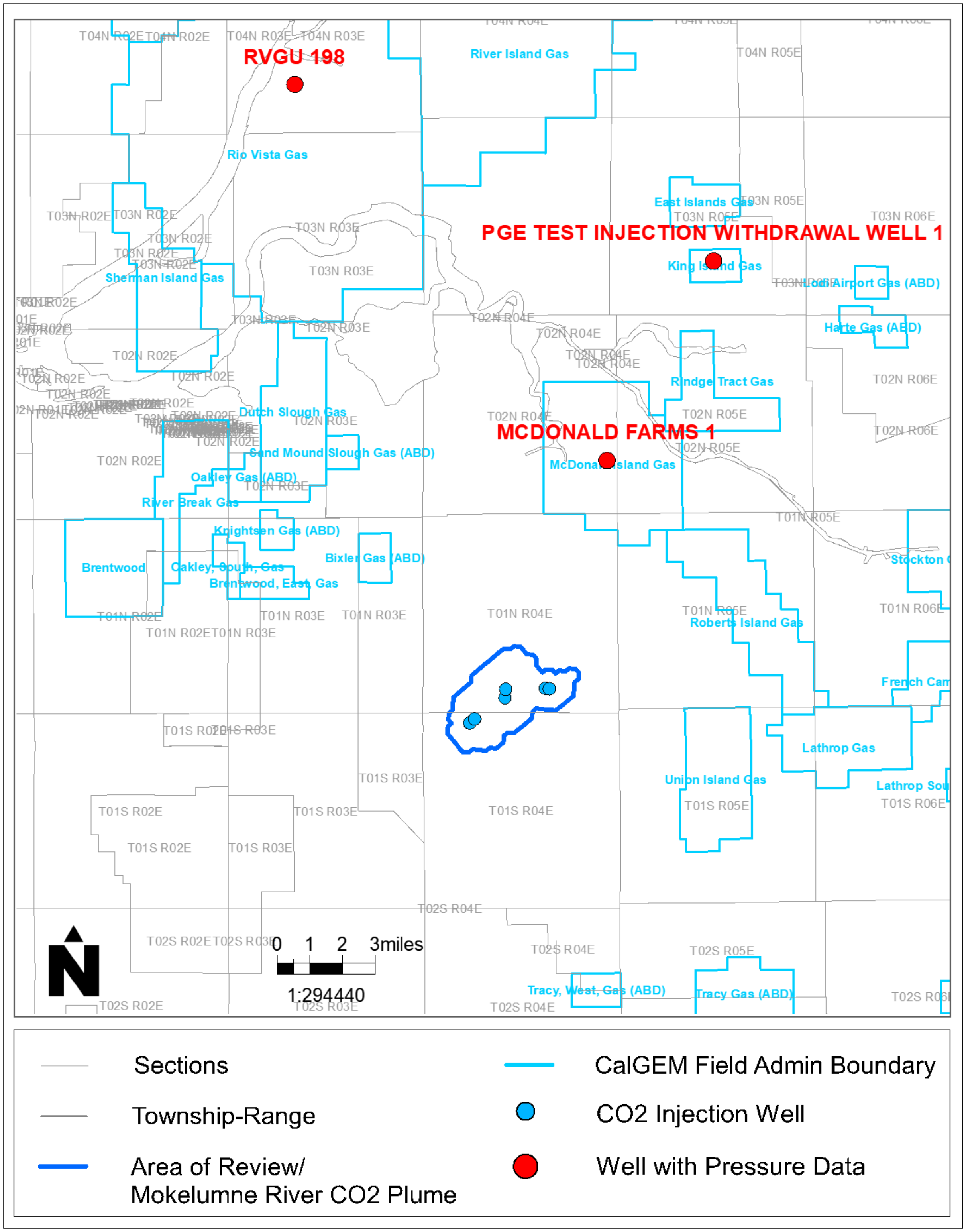


Figure B-15. Map showing location of wells with pressure data for the Mokelumne River Formation.

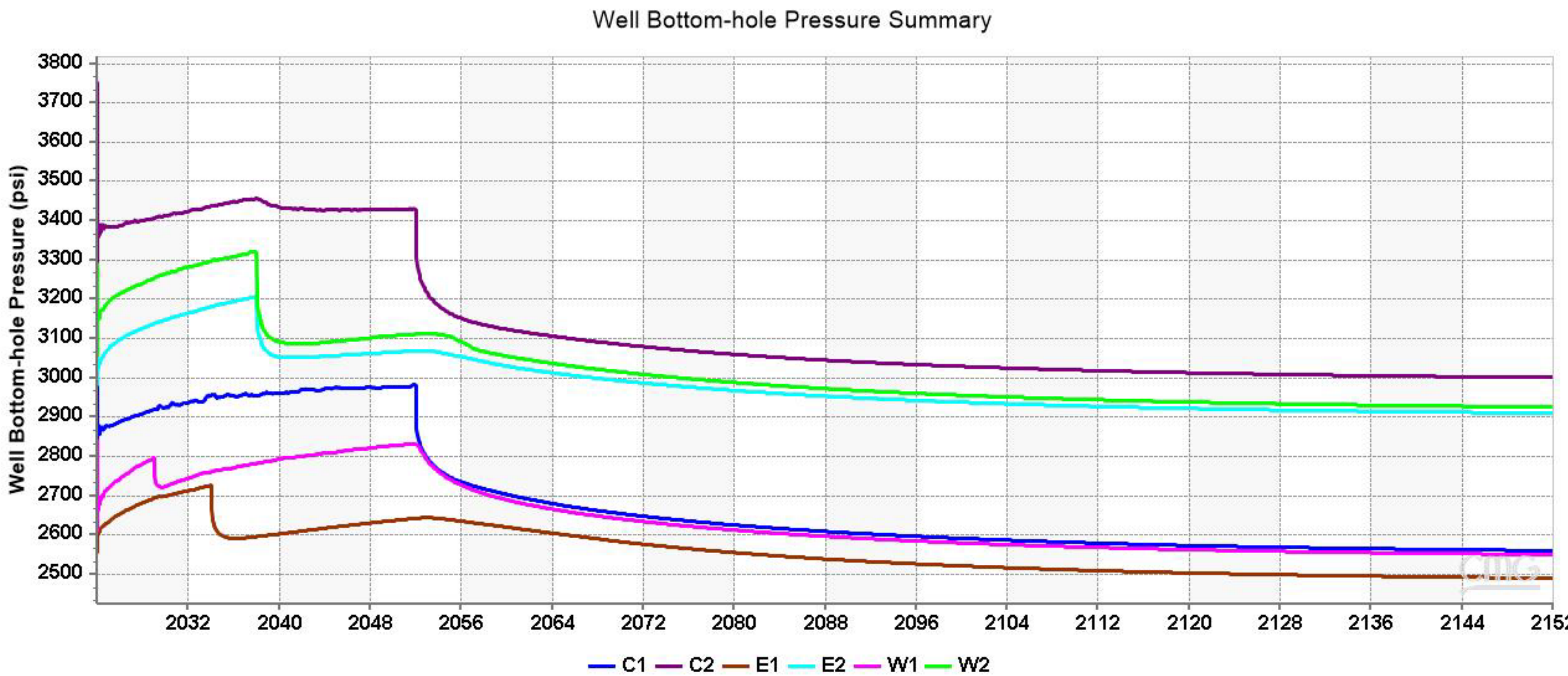


Figure B-16. Well bottomhole pressure at each injector through time.

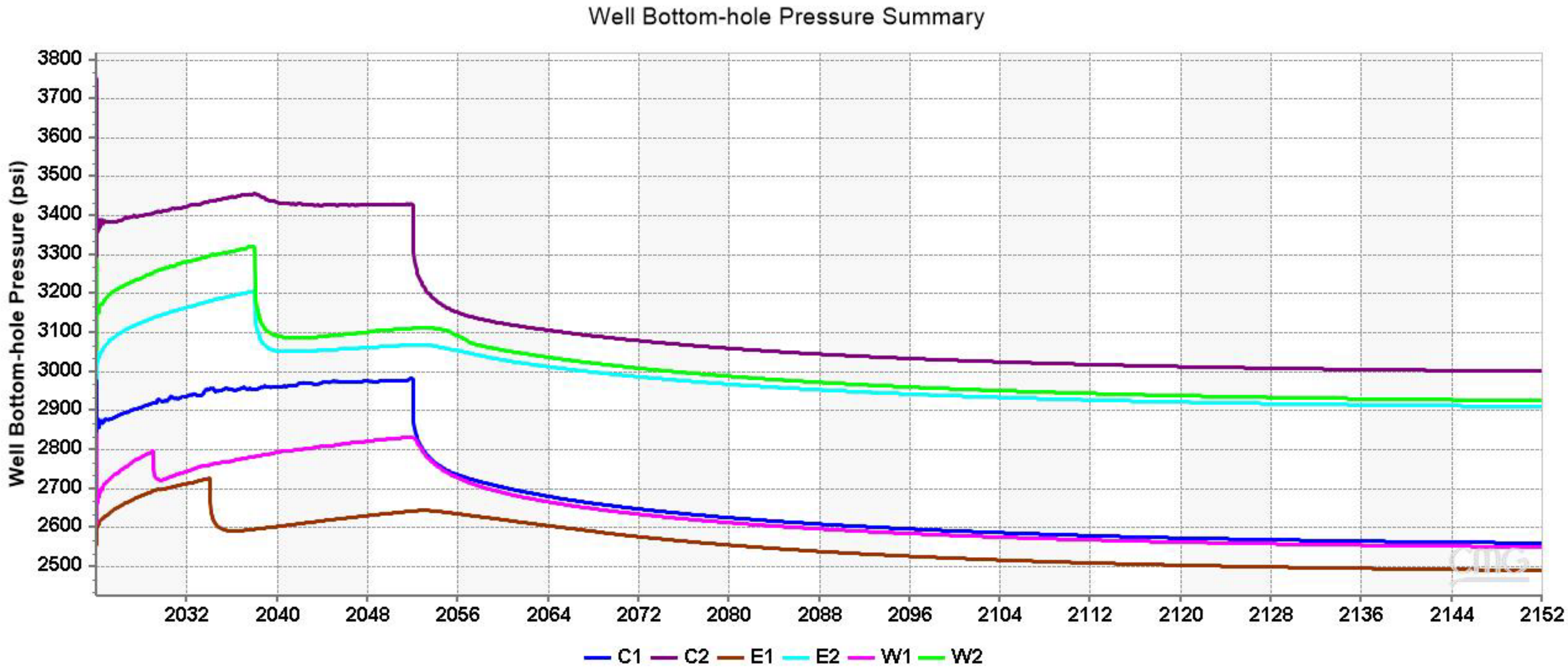


Figure B-17. Reservoir pressures near each injector through time.

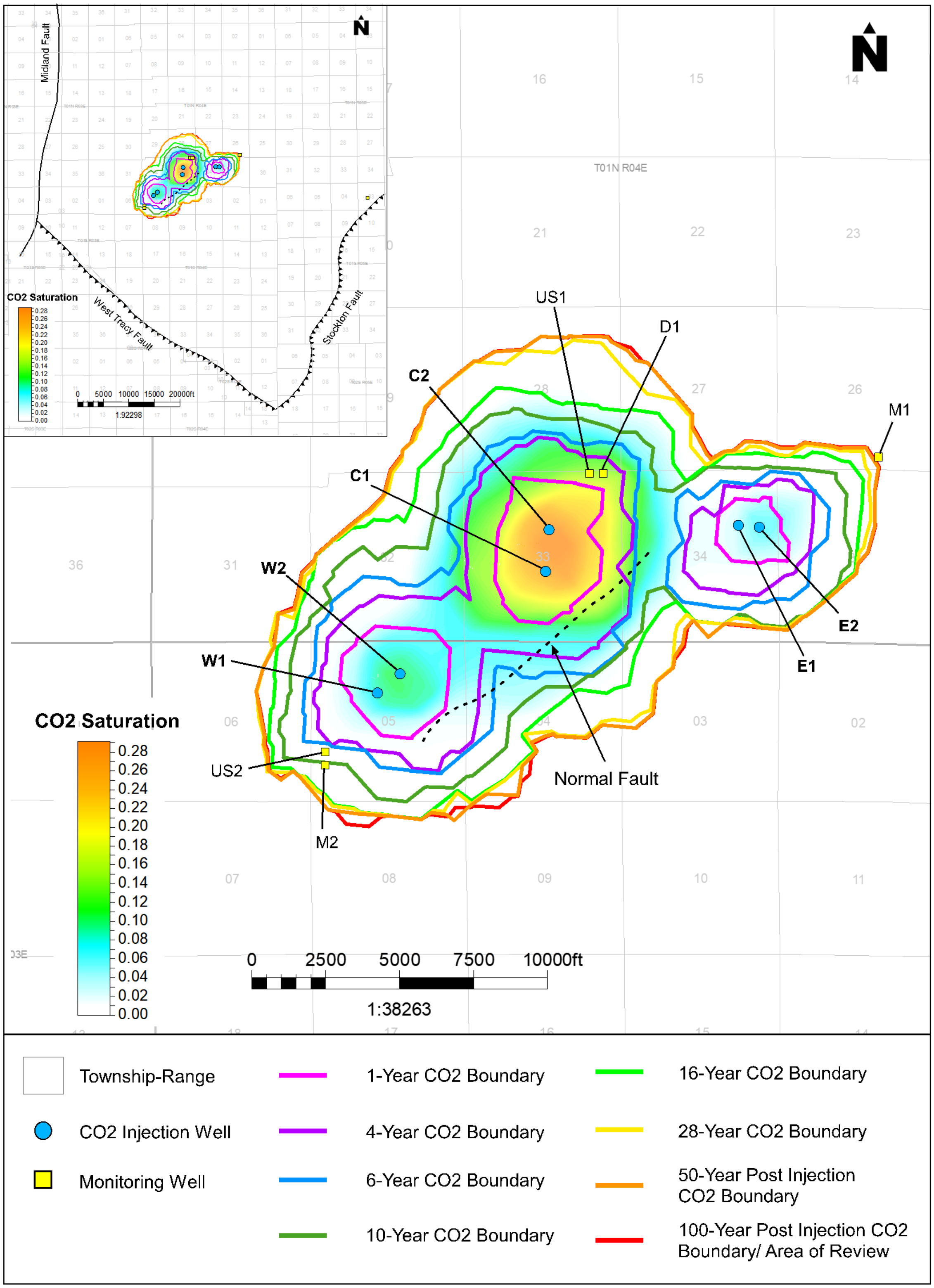


Figure B-18. Plume development through time: 1-year, 4-year, 6-year, 10-year, 16-year, 28-year (end of injection), 50-year post injection and 100-year post injection. CO2 Saturation is for the 100-year plume.

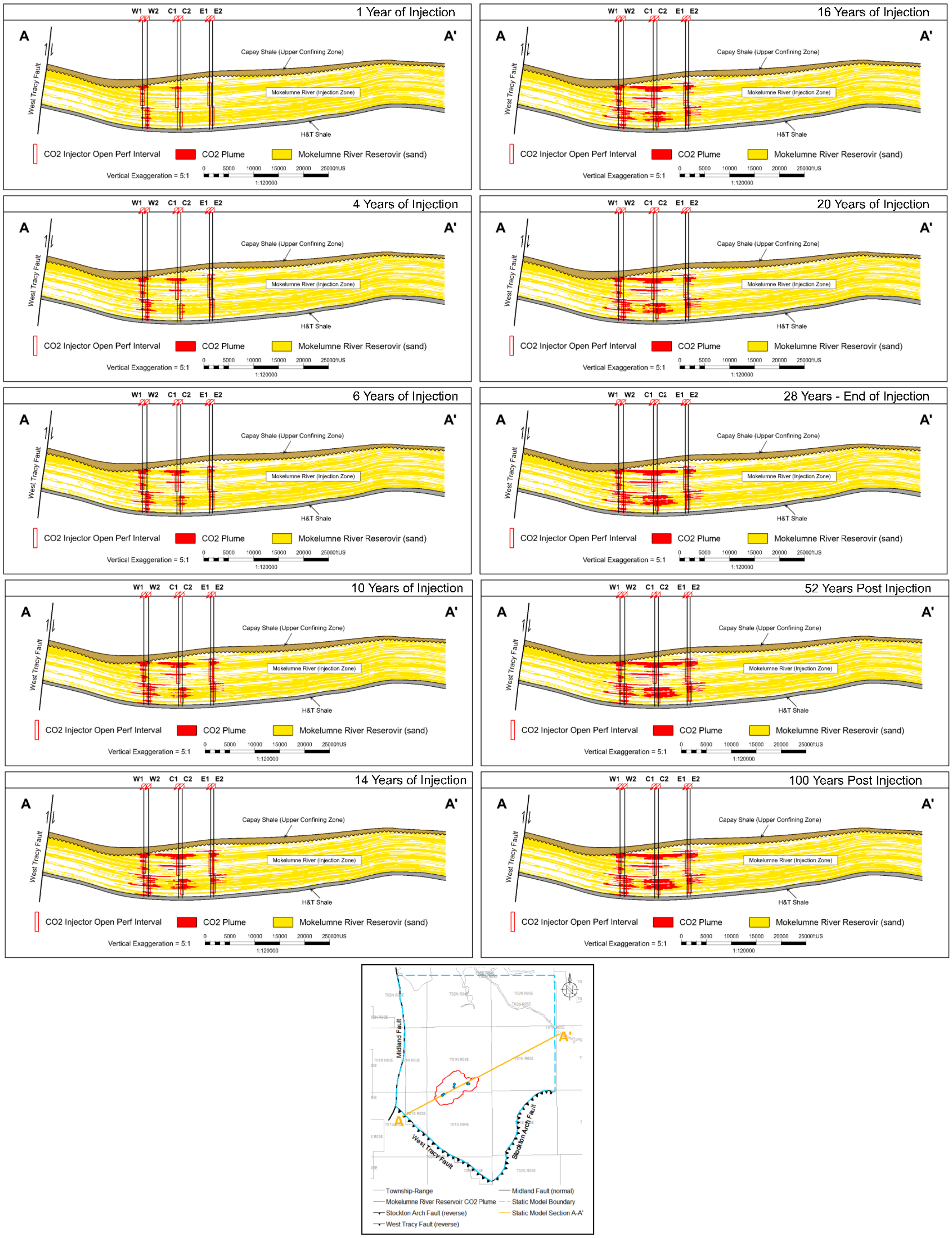


Figure B-19. Cross sections showing maximum plume development with depth at various time steps through the project.

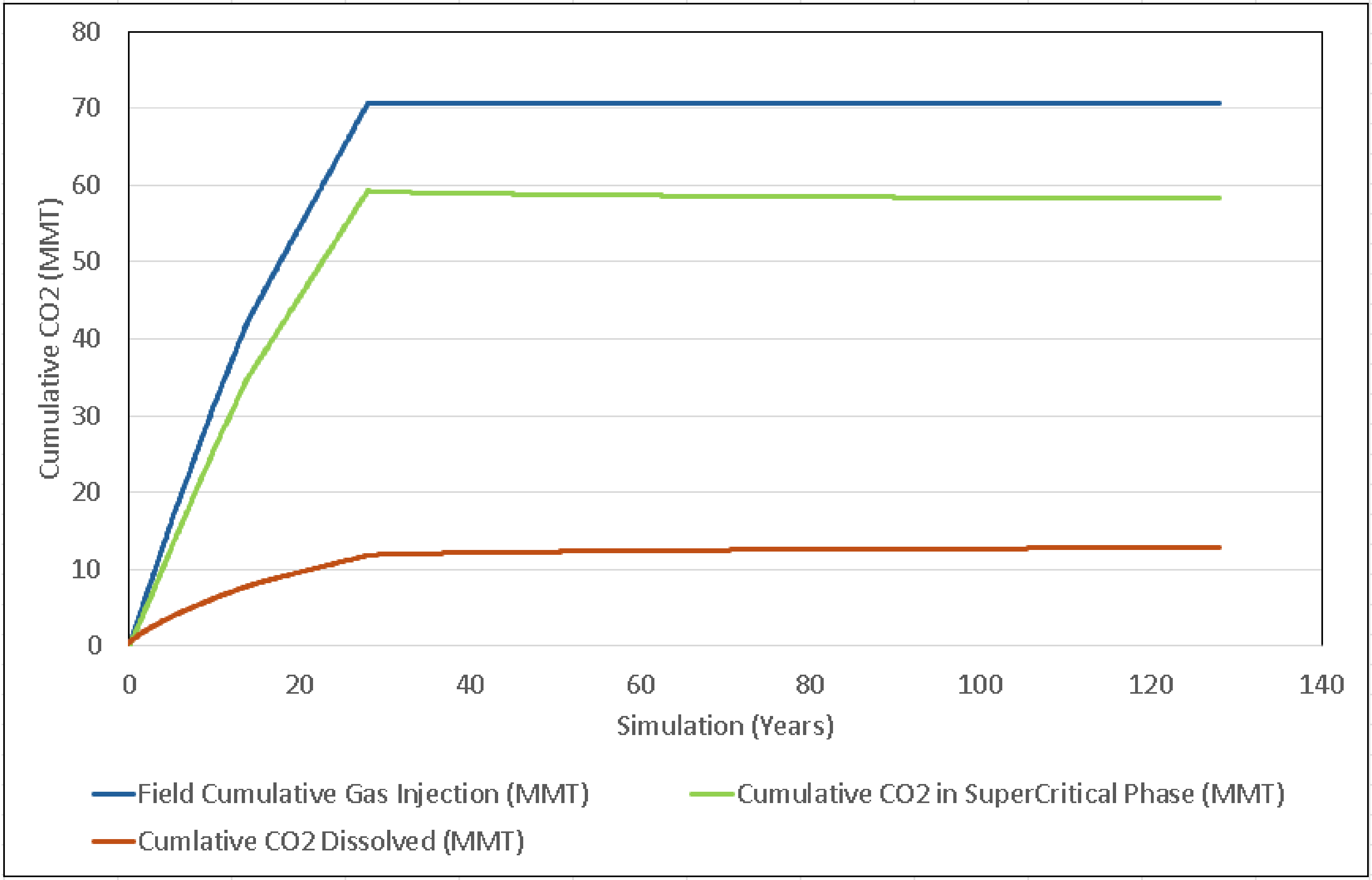


Figure B-20 CO_2 storage mechanisms in the reservoir.

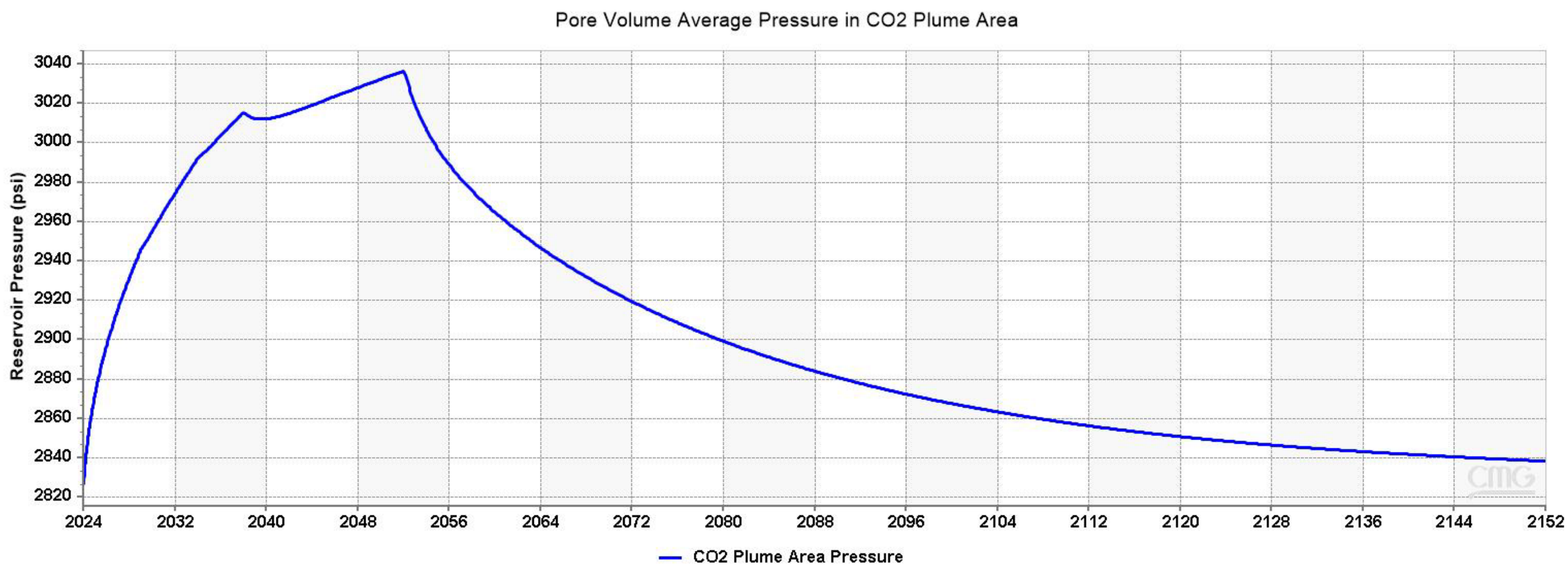


Figure B-21. Pore volume average pressure in CO2 plume area through time.

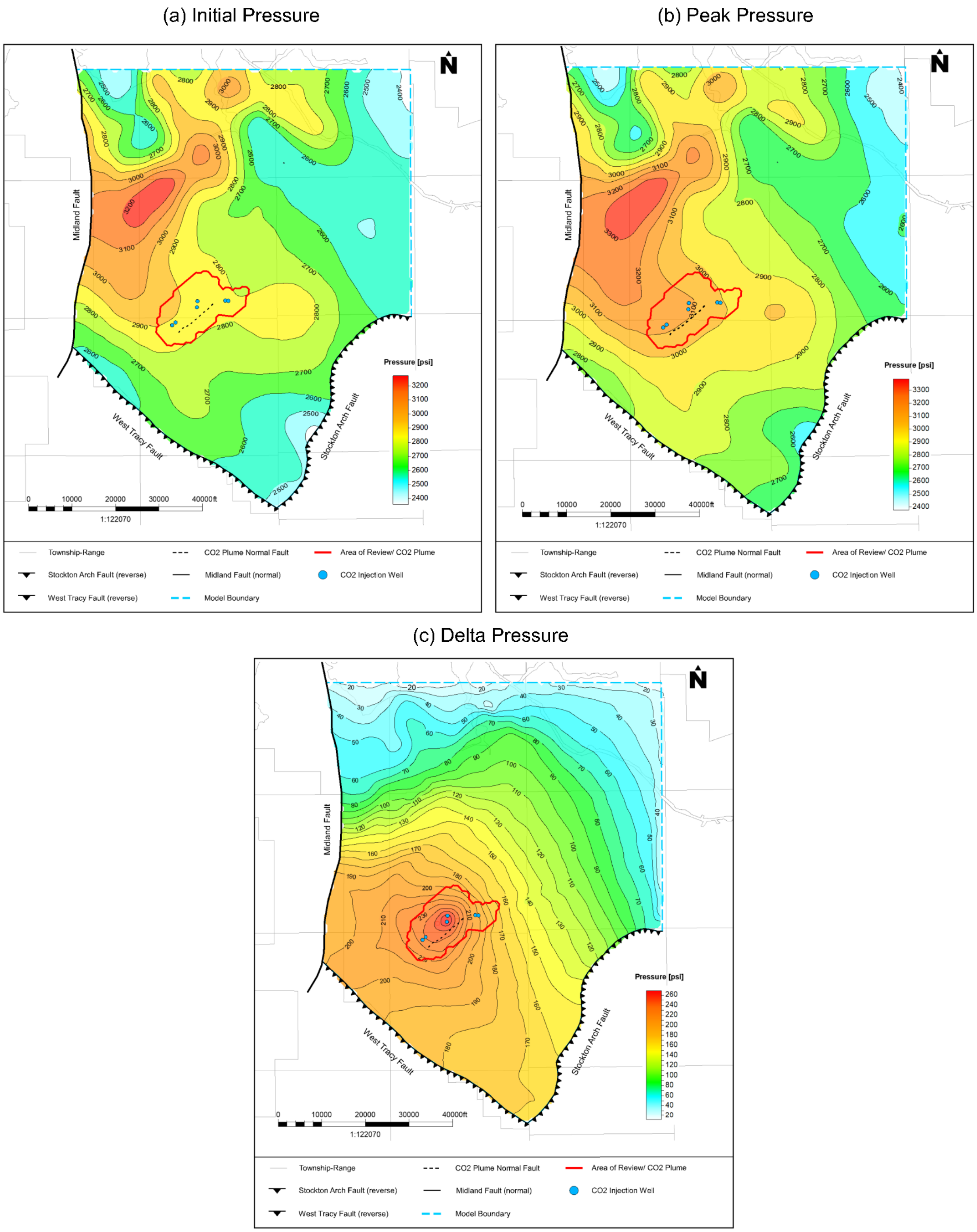


Figure B-22. (a) Initial pressure across the model boundary, (b) Peak pressure across the model boundary, (c) Delta pressure across the model boundary.

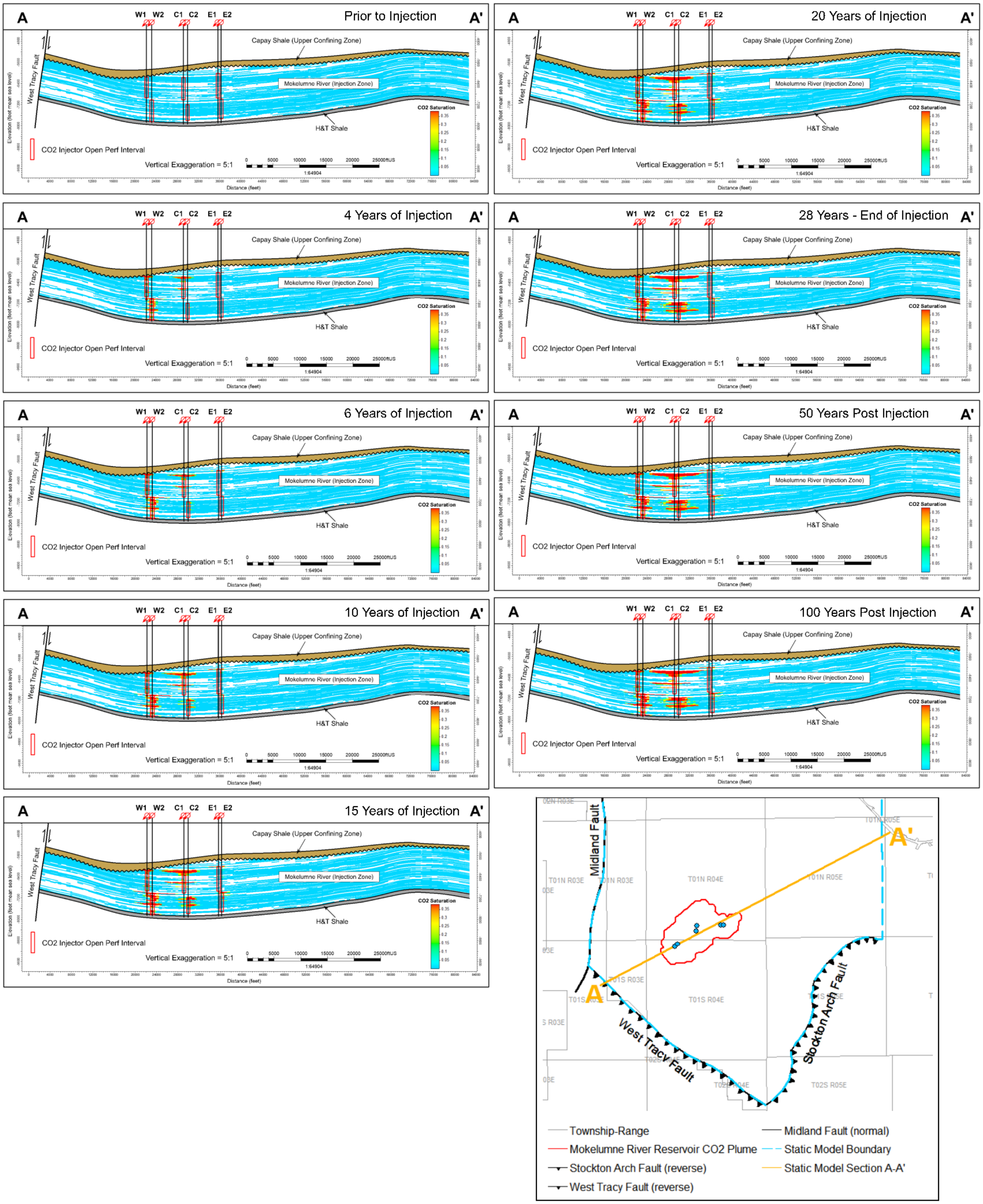


Figure B-23. Cross sections showing CO_2 saturation at various time steps through the project.

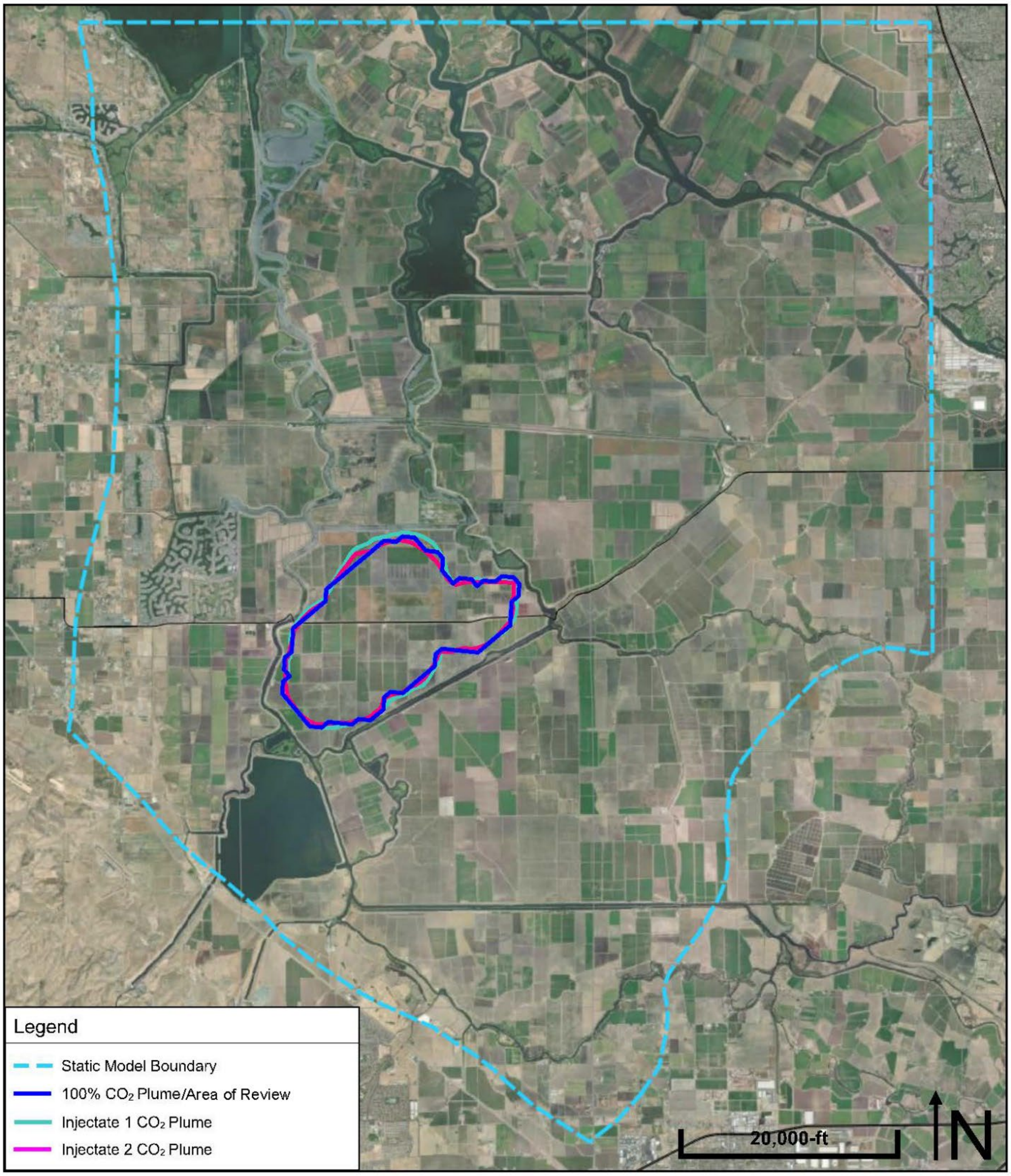


Figure B-24. **AoR/CO_2 plume outlines for Injectate 1 (Light Blueish Green), Injectate 2 (Pink) and 100% CO_2 Cases (Dark Blue). Minimal difference in AoR/CO_2 Plume boundaries between the 3 cases with the boundaries overlying each other for the most part.**

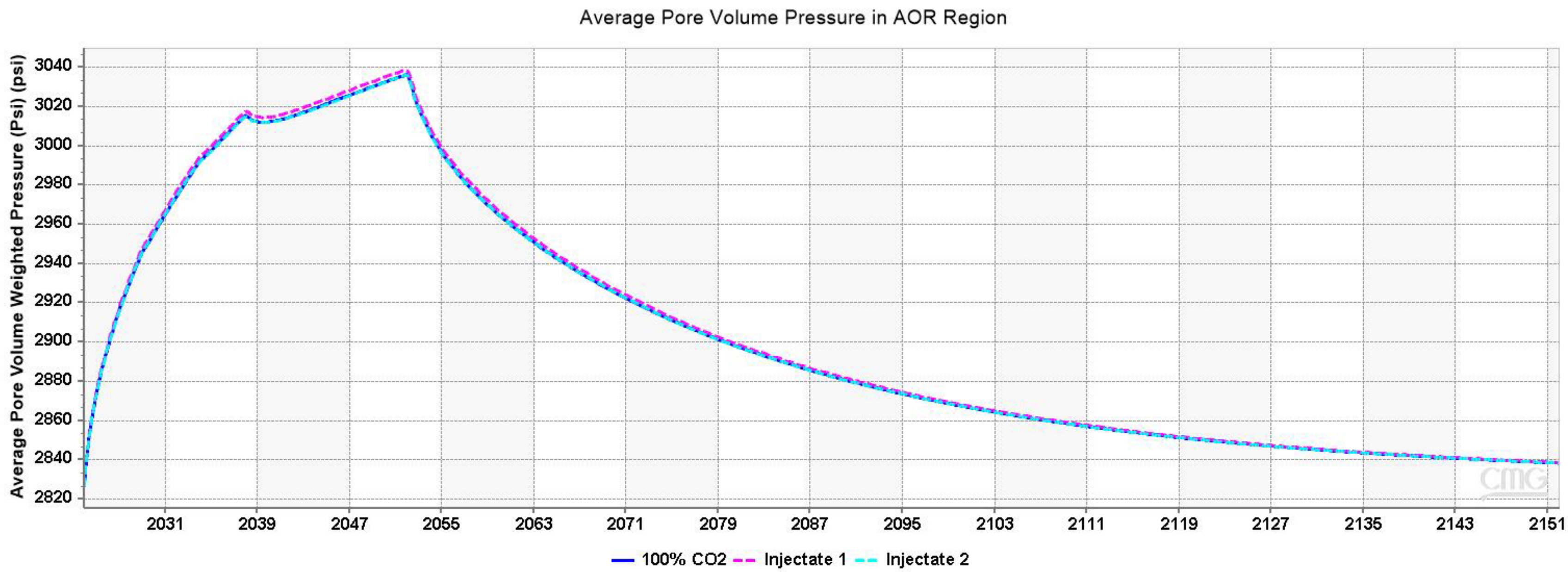


Figure B-25. Reservoir pressure within approximate AoR for Injectate 1, Injectate 2 and 100% CO_2 cases. 100% CO_2 case and Injectate 2 case pressure trends plot almost on top of each other.

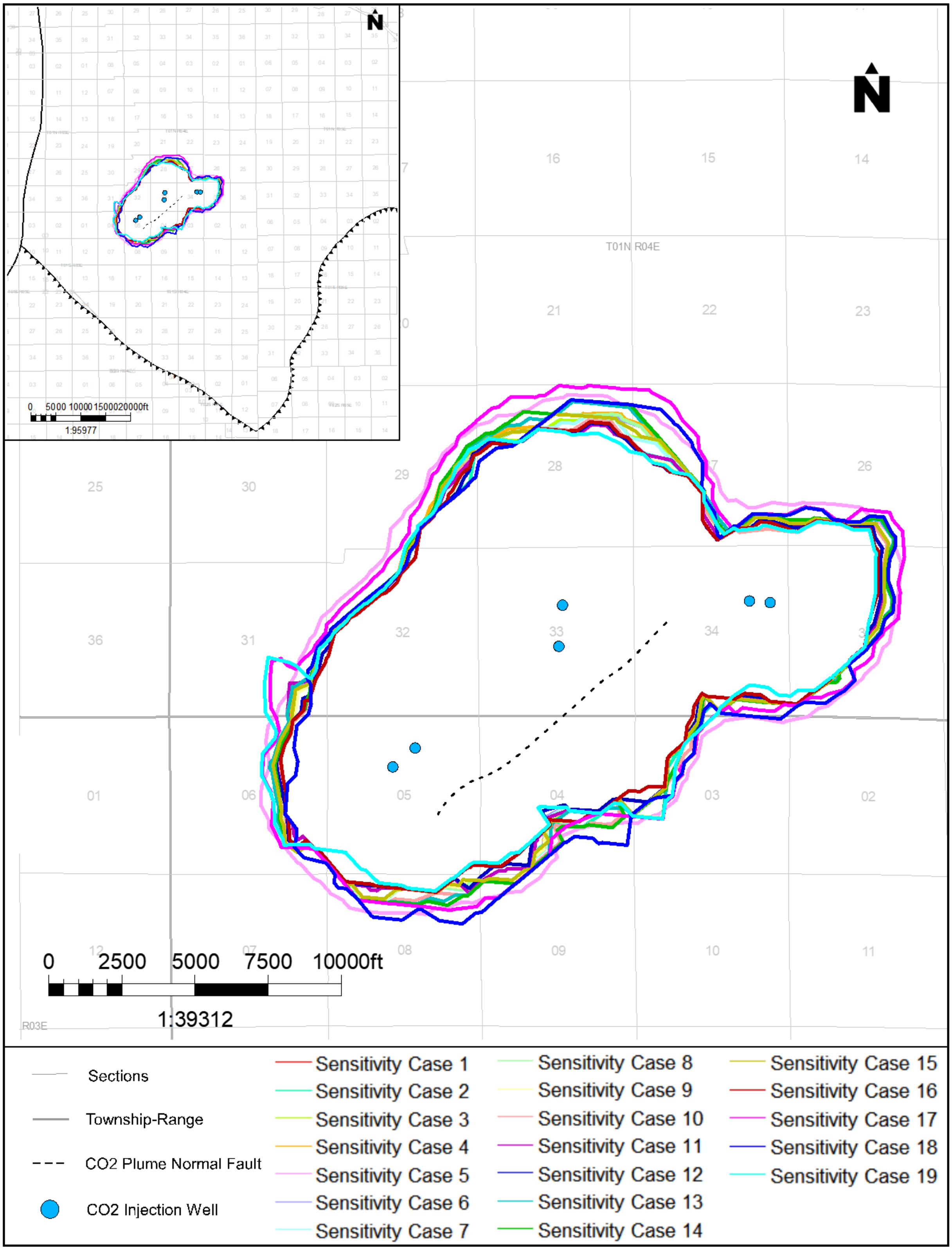


Figure B-26 CO_2 plume area for sensitivity cases.

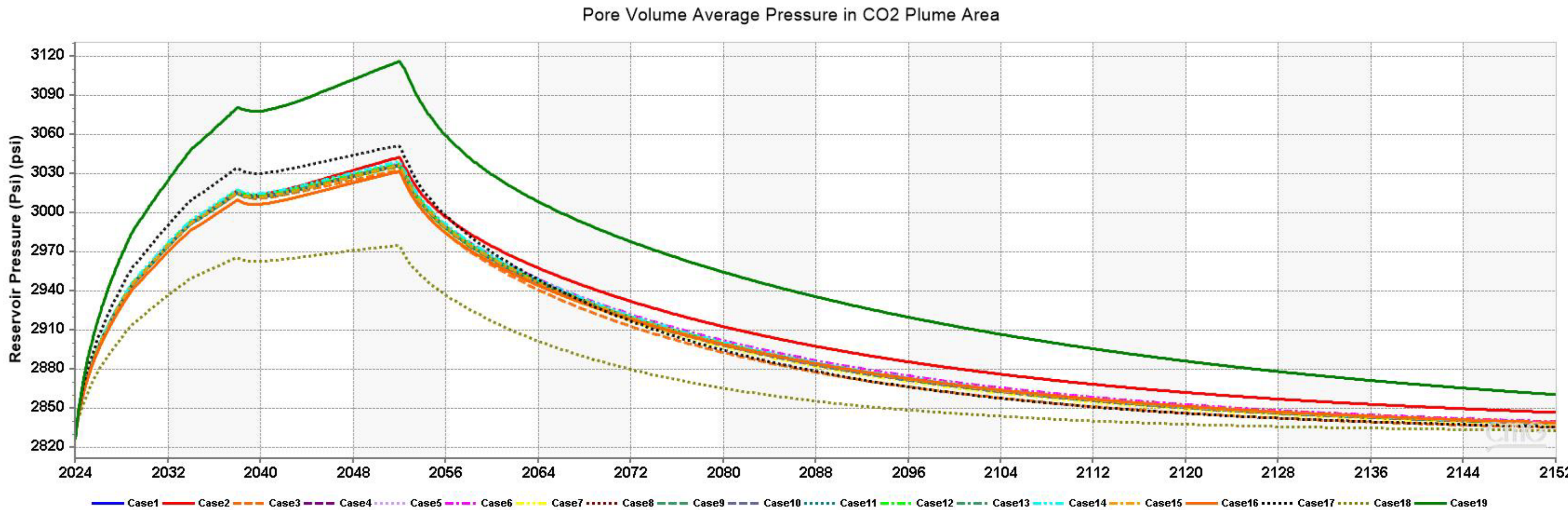
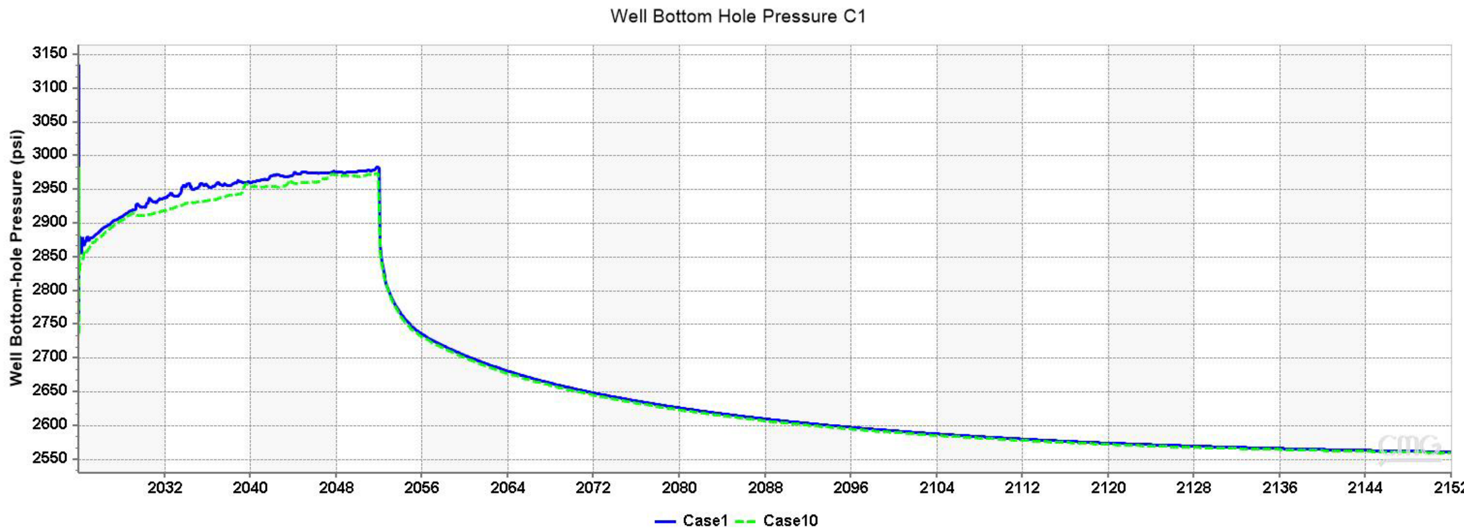


Figure B-27. Pore volume averaged pressure in CO2 plume area for sensitivity cases.



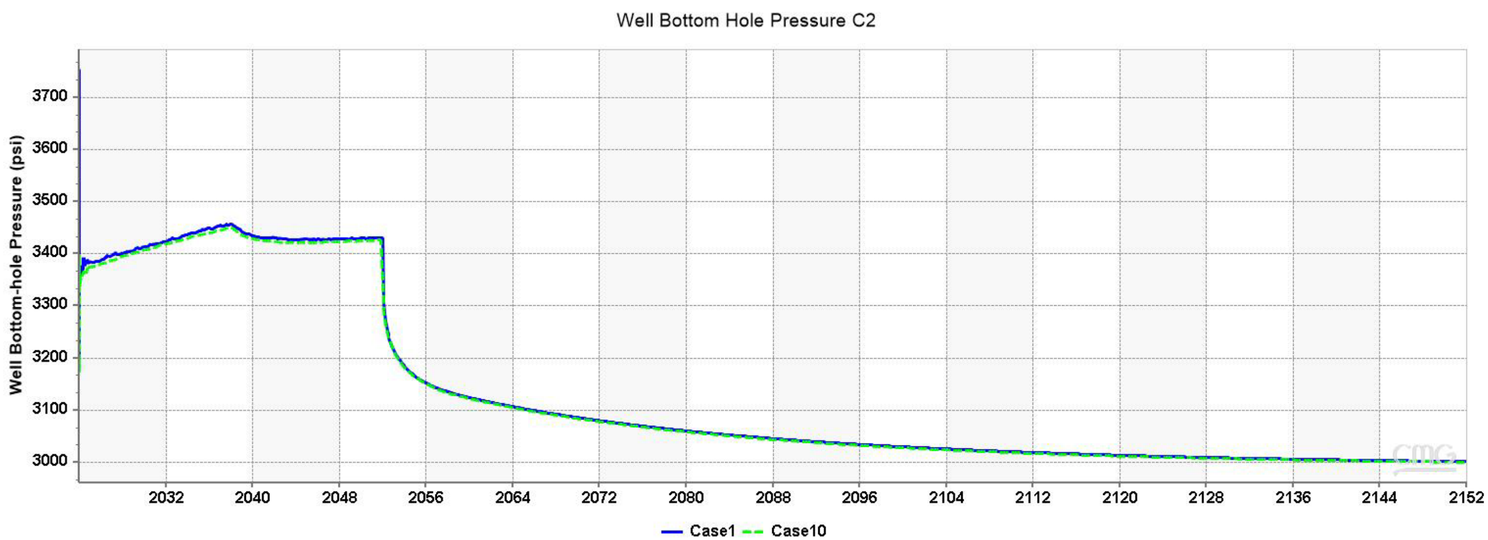
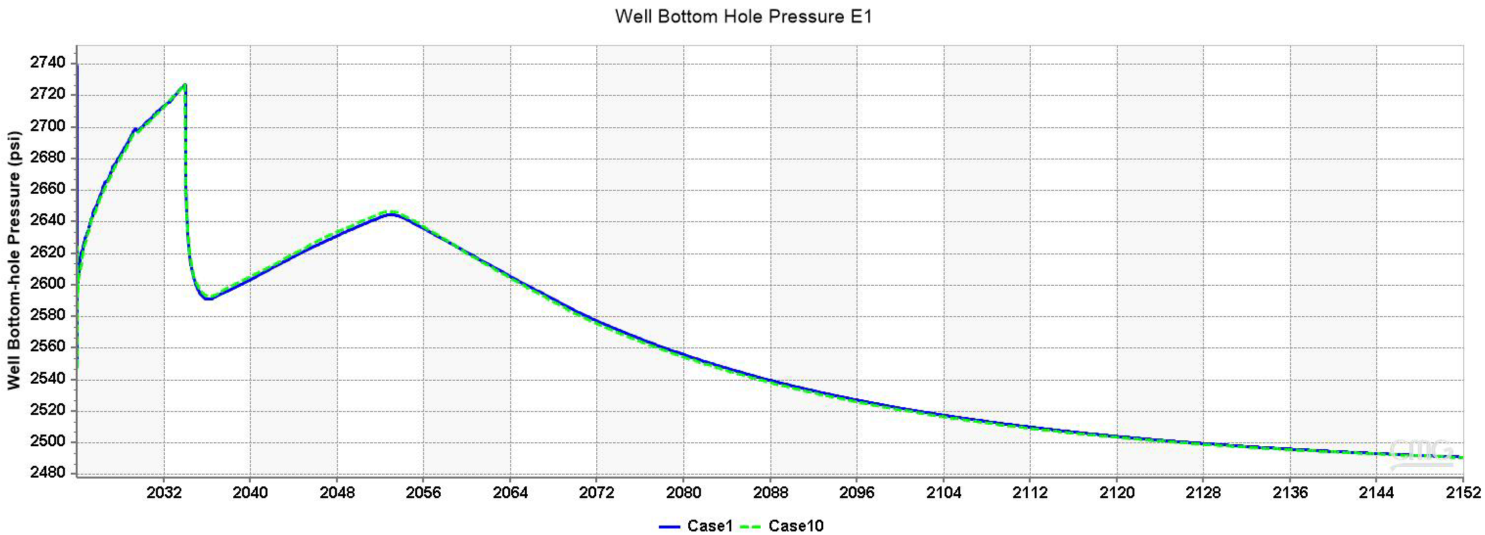


Figure B-28a. Bottomhole pressures for injectors C1 and C2 for the reference Case 1 and sensitivity Case 10 (local grid refinement).



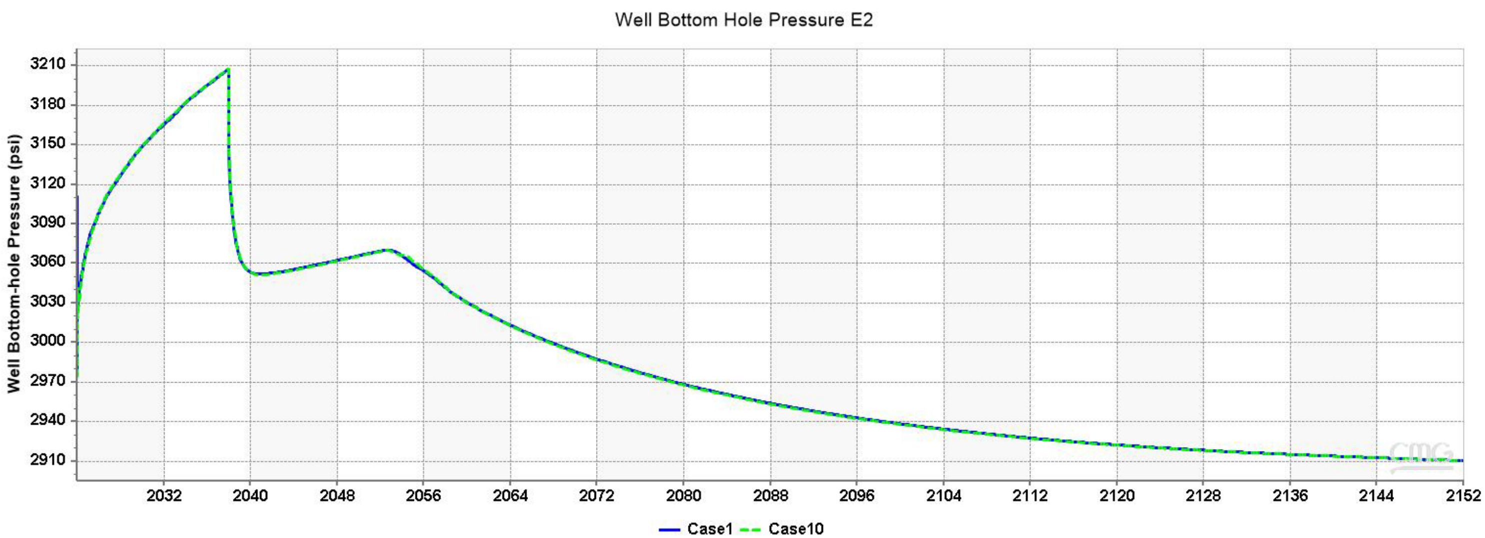
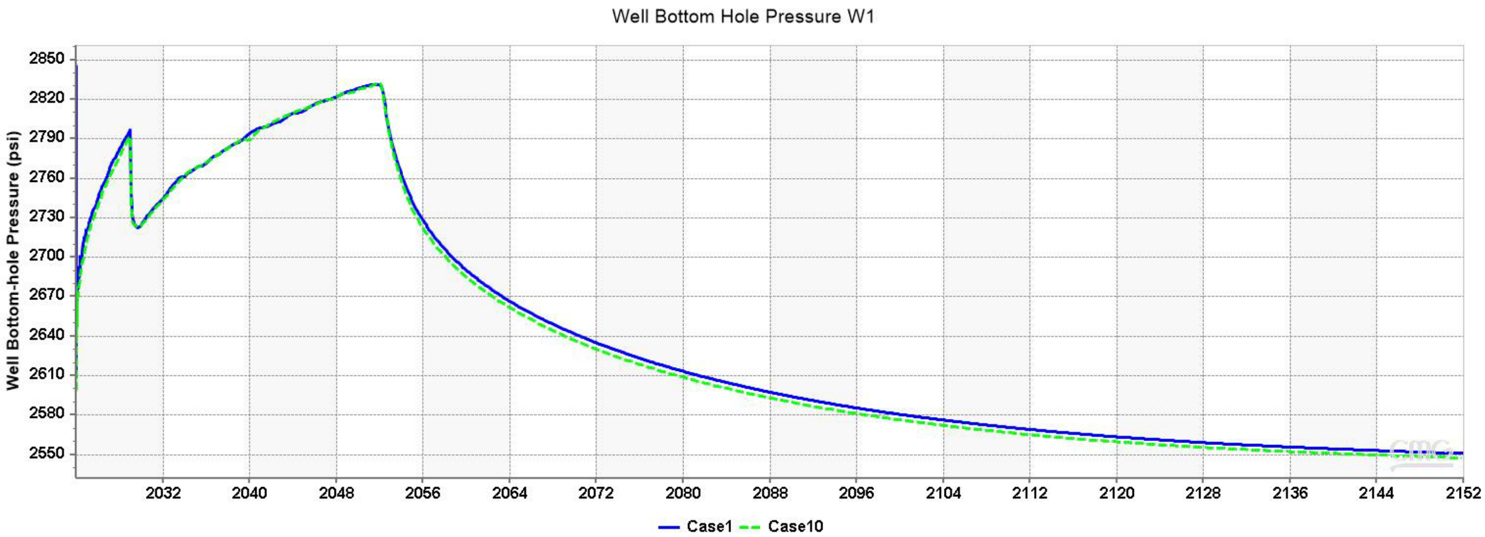


Figure B-28b. Bottomhole pressures for injectors E1 and E2 for the reference Case 1 and sensitivity Case 10 (local grid refinement).



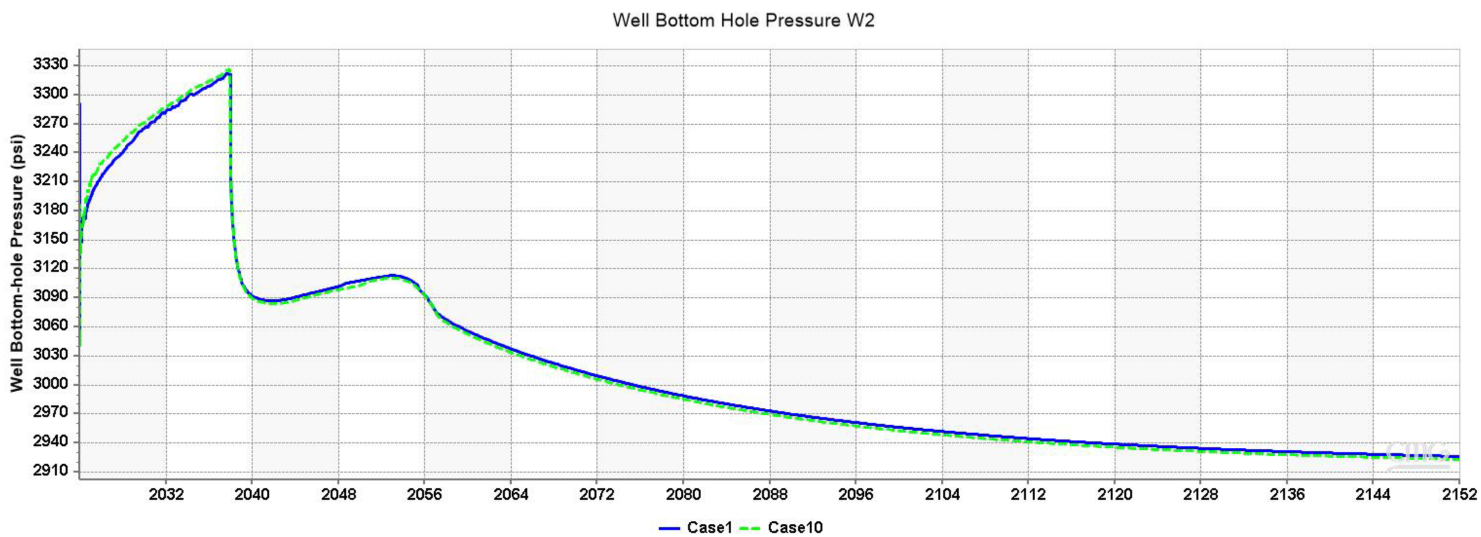


Figure B-28c. Bottomhole pressures for injectors W1 and W2 for the reference Case 1 and sensitivity Case 10 (local grid refinement).

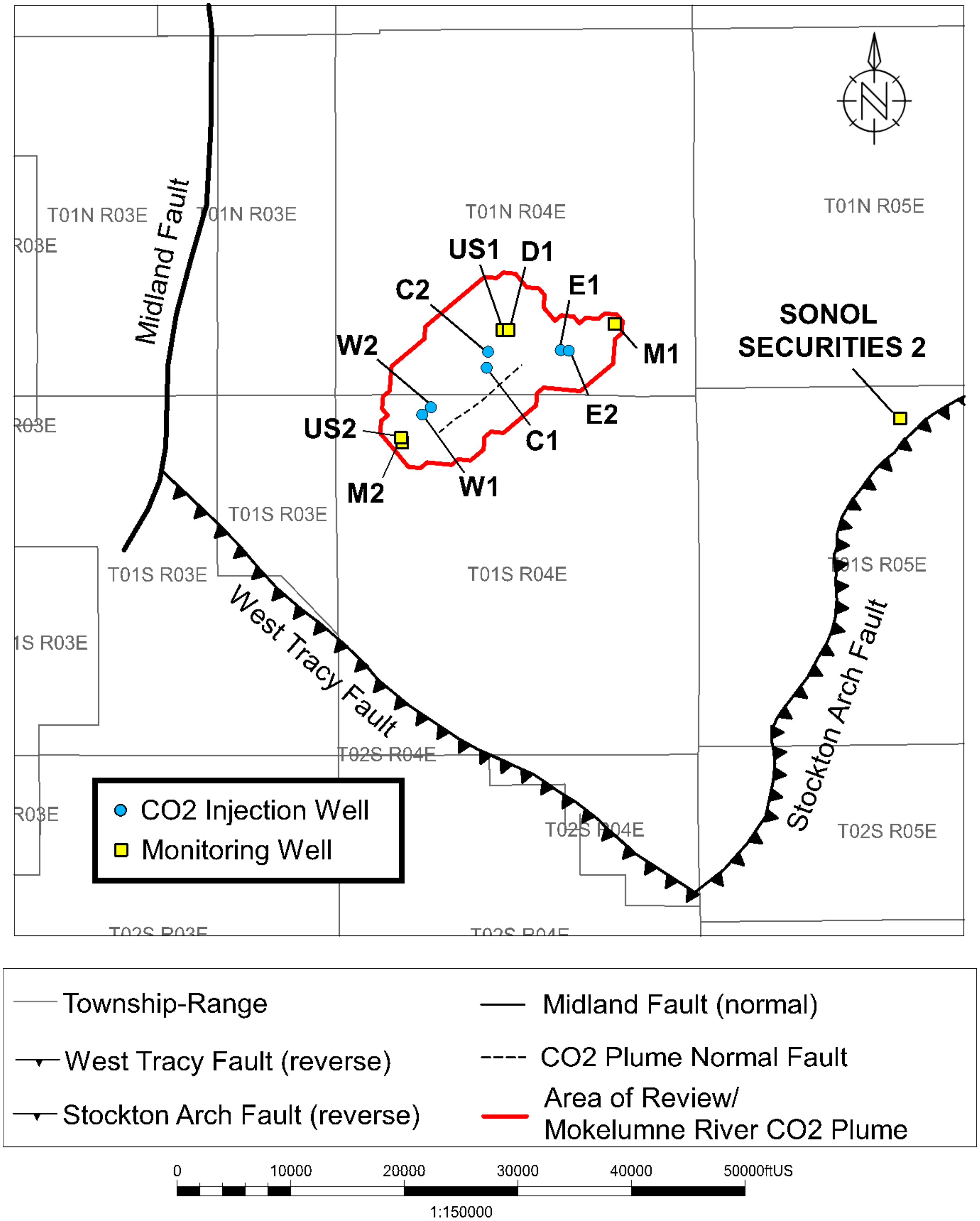


Figure B-29. Map showing the location of injection wells and monitoring wells.

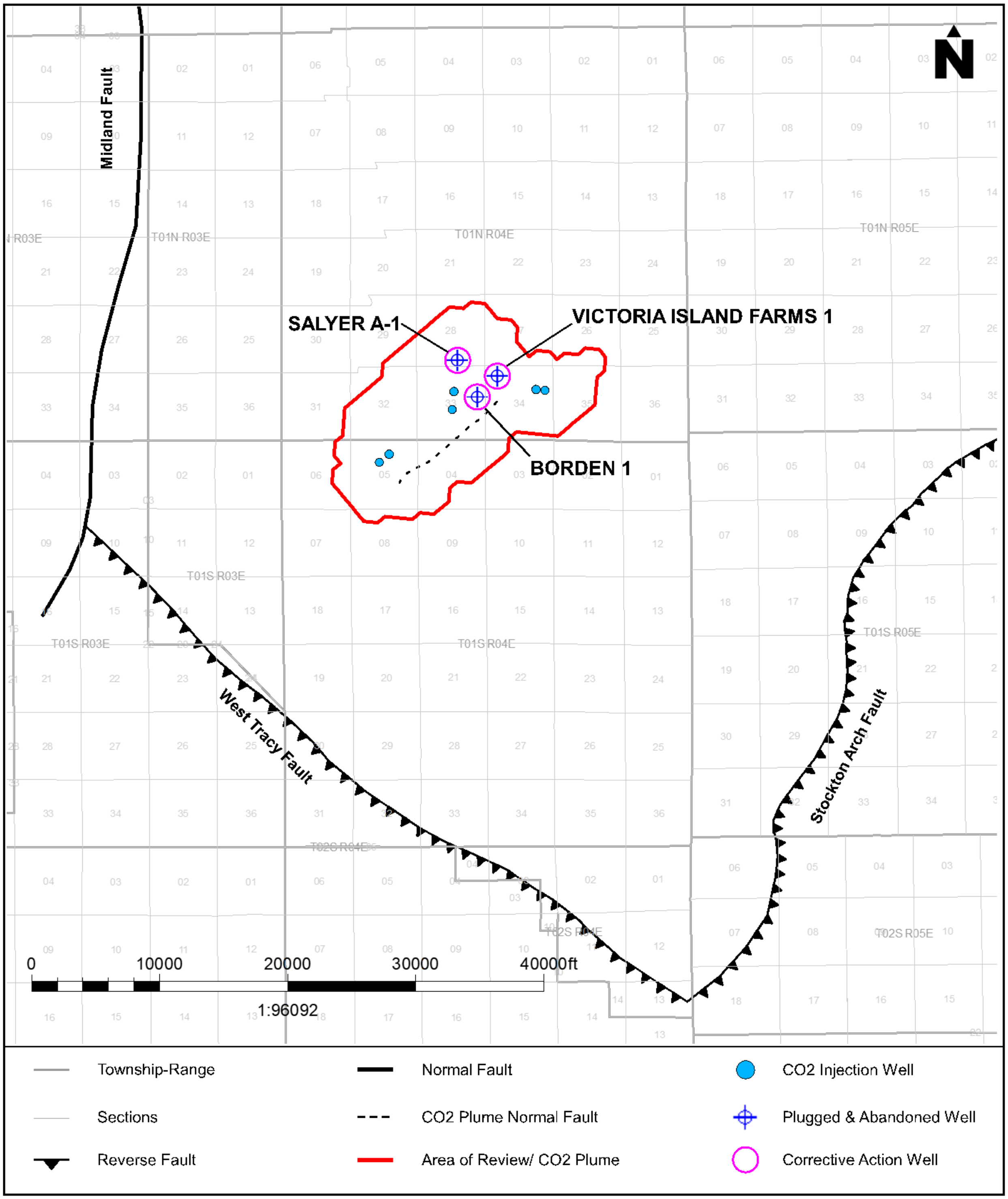


Figure B-30. Wells penetrating the Capay Shale confining layer and Mokelumne River Formation sequestration reservoir reviewed for corrective action. Wells requiring corrective action prior to injection are identified by magenta circles.

Tables

Table B-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 B-2. Initial Conditions

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	151	Fahrenheit	6,900	Bottomhole temperature data from logs in the area (Figure B-13)
Formation pressure	2860	Pounds per square inch	6,900	Downhole RFT data from PGE Test injection / Withdrawal well 1 adjusted to depth (Figure B-14 and B-15)
Salinity	15,500	Parts per million	6,900	Water analysis and Log calculated salinity curves as discussed in Attachment A, Section 2.8.2.

Table B-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 (feet) 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
Number of perforated intervals	11	5	14	6	7	8
Perforated interval (feet TVD) Top, Bottom	6176, 7016	7192, 7790	6010, 6950	6980, 7720	6150, 6930	7020, 7840
Casing diameter (inch)	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).

Table B-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	3106 / 0.503	3485 / 0.485	2791 / 0.464	3270 / 0.468	2903 / 0.472	3420 / 0.487

Table B-5. Simulation Sensitivity Scenarios

Case	Description	Reference	Perturbation
1	Reference Case:	Reservoir Model set up with Carter-Tracy Aquifer on the boundary cells connected at the Northern and Eastern Boundaries Aquifer Properties: Thickness = 1,000 feet; Phi = 0.3; Permeability = 200 millidarcy; Reservoir Radius = 45,000 feet; Angle = 0.5 (Fraction of Circle); Aquifer Radius to Reservoir Radius = 200;	
2	Aquifer Sensitivity	Case 1	Permeability = 100 millidarcy
3	Aquifer Sensitivity	Case 1	Permeability = 300 millidarcy
4	Aquifer Sensitivity	Case 1	Aquifer Radius to Reservoir Radius = 100
5	Aquifer Sensitivity	Case 1	Aquifer Radius to Reservoir Radius = 1
6	Aquifer Sensitivity	Case 1	Aquifer Thickness of 900 feet
7	Aquifer Sensitivity	Case 1	Aquifer Thickness of 1,000 feet
8	Aquifer Sensitivity	Case 1	Aquifer Phi = 0.28
9	Aquifer Sensitivity	Case 1	Aquifer Phi = 0.32
10	Study grid refinement effects	Case 1 Area grid size: Grid spacing around injectors at 50ft.	New refinement sets grid spacing at 25 feet around injectors
11	Study differences caused due to capillary pressure	Case 1	Updated Mokelumne Capillary pressure
12	Reduced end point scaling parameter for critical and connate water saturation	Case 1 Swcr = 0.34; Swirr = 0.34	Swcr=0.25; Swirr=0.25
13	Increased end point scaling parameter for critical and connate water saturation	Case 1 Swcr = 0.34; Swirr = 0.34	Swcr=0.40; Swirr=0.40
14	Injectate 1	Case 1: CO_2 and Brine as two component model	6 component model set up with properties for Injectate 1
15	Injectate 2	Case 1: CO_2 and Brine as two component model	6 component model set up with properties for Injectate 2
16	P90 case realization for Porosity	Case 1	Porosity multiplier of 1.10; Permeability is not modified
17	P10 case realization for Porosity	Case 1	Porosity multiplier of 0.83; Permeability is not modified
18	P90 case realization for Permeability	Case 1	Permeability multiplier of 2.0; Porosity is not modified
19	P10 case realization for Permeability	Case 1	Permeability multiplier of 0.5; Porosity is not modified

Table B-6. Wellbores in the AoR by Status

Status	Count
Active	0
Idle	0
Plugged and Abandoned	3
Total	3