

Application No. 45079, 45080, 46169, 46170, and 46171

AREA OF REVIEW AND CORRECTIVE ACTIONS PLAN

Pelican Sequestration Project

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1.0 Facility Information

Facility name: Pelican Sequestration Project
Pelican CCS 1, Pelican CCS 2, Pelican CCS 3, Pelican CCS 4, and Pelican CCS 5 wells

Facility contact: Tyler Spoede, Project Manager
5 Greenway Plaza Houston, TX 77046
713-985-6954 william_spoede@oxy.com

Well location: Livingston Parish, Louisiana

Well Name	Longitude (NAD 27)	Latitude (NAD 27)	Longitude (NAD 83)	Latitude (NAD 83)
Pelican CCS 1	-90° 40' 55.76"	30° 35' 19.16"	-90° 40' 56.10"	30° 35' 19.83"
Pelican CCS 2	-90° 40' 58.83"	30° 34' 53.98"	-90° 40' 59.17"	30° 34' 54.66"
Pelican CCS 3	-90° 43' 50.13"	30° 36' 10.56"	-90° 43' 50.48"	30° 36' 11.24"
Pelican CCS 4	-90° 44' 29.72"	30° 36' 41.03"	-90° 44' 30.06"	30° 36' 41.70"
Pelican CCS 5	-90° 46' 30.21"	30° 37' 35.26"	-90° 46' 30.56"	30° 37' 35.93°

2.0 Computational Modeling Approach

This plan discusses the Area of Review (AoR) delineation and provides corrective actions needed in the wells that penetrate the Upper Confining Zone within the AoR. Delineation of the AoR is one of the key elements in the Class VI permit to ensure underground sources of drinking water (USDWs) in the region surrounding the geologic sequestration project are not endangered by the injection activity.

The AoR is determined using a multiphase CO₂-brine transport model, which is constructed from a sophisticated geologic model that accounts for site-specific hydrogeology. The methods and approaches for developing this complex multiphase simulation model and delineating the AoR are defined below.

2.1 Model Background

Our modeling approach included both static and dynamic model grids. The structural grid and properties from the fine-scale static model were upscaled vertically by removing shallow zones to a suitable dynamic multiphase flow model grid. This provided a good balance between computational demand and maintaining reservoir heterogeneity.

2.1.1 Static Geological Model

The static geological model was constructed in 2024 using SLB's Petrel (v.2023) 3D gridding and geostatistical modeling software. This static model captures detailed heterogeneity incorporating data and interpretations from the stratigraphic well Pelican MLR 004 drilled in 2022. The static

model grid uses high vertical resolution around 4 ft to accurately capture heterogeneity associated observed at the log scale. Observations and interpretations at wells were propagated throughout the model convolving geological trends.

2.1.2 Model Name and Authors/Institution

The modeling software is GEM (v2024.10) reservoir simulator with the Greenhouse Gas (GHG) module from Computer Modeling Group Ltd.

2.1.3 Dynamic Multiphase Flow model

GEM is a commercially available, compositional, finite-difference simulator commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model several carbon capture and storage projects. The Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: a H₂O-rich phase (liquid), CO₂-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, and enthalpy) of the H₂O and CO₂ phases and CO₂ solubility in H₂O are calculated from a correlation suitable for a wide range of typical storage reservoir conditions, including temperature ranges between 12°C and 150°C and pressures up to 110 MPa. Details of this method can be found in Collins et al. (1992), Thomas and Thurnau (1983), and Nghiem and Li (1989).

Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The CO₂-rich phase (gas) density is obtained using a cubic equation of state developed by Peng and Robinson (1976). The Peng-Robinson equation of state is described below in Equation 1:

$$P = \frac{RT}{(V-b_{mix})} - \frac{a_{mix}}{(V^2+2Vb_{mix}-b_{mix}^2)} \dots\dots\dots \text{(Equation 1)}$$

Where:

v is the molar volume;

P is the pressure;

T is the temperature in Kelvin;

R is the universal gas constant;

a_{mix} and b_{mix} are mixture-specific functions of temperature and composition, calculated from the critical properties and acentric factors of the components.

- The CO₂ dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey, 1996).

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- The brine density is specified at a reference pressure of 2,400 psi and corrected for local pressure variations using a specified water compressibility, $5.0 \times 10^{-6} \text{ psi}^{-1}$. It is then corrected for the dissolved CO_2 and ionic components using their partial molar volumes. The brine viscosity is calculated using the Kestin (1981) correlation. The details can be found in the publication by Kestin et al. (1981).
- Chemical equilibria among H^+ , Ca^{2+} , Mg^{2+} , K^+ , Na^+ , Al^{3+} , SiO_2 , HCO_3^- , OH^- , CO_3^{2-} , CaOH^+ ions in the aqueous phase are modeled with the CMG GHG module. The solid phase includes anorthite, calcite, illite, and kaolinite minerals. Reactions among these minerals and ions are modeled using the chemical reactions and reaction coefficients from a Lawrence Livermore National Laboratory database (Thibeau, 2007), which were also used in a simulation study by Nghiem et al. (2004).
- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).

The CMG WinProp software has a built-in library for the properties of CO_2 and CH_4 , based on Reid et al. (1977). No changes were made to the library components.

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

The CO_2 delivery temperature to the injection well is estimated to be between 60°F and 120°F. Therefore, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. As such, the simulations were based on isothermal operating conditions with a linear initial reservoir temperature gradient of 20°C/km (0.01075°F/ft), as obtained from the Pelican MLR 004 stratigraphic well, and a surface temperature of 86°F (Nicholson, 2012).

With respect to the time step selection, the software algorithm optimizes the time step duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the time step size ranged from 0.001 to 10 days. In all cases, the maximum solution change over a time step was monitored and compared with the specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. New time steps are chosen so that the predicted solution change is less than a specified target.

Chemical equilibria of ionic species in brine and reactions of minerals with ions were simulated in only limited cases due to their long computing times. Results suggested negligible net carbon capture by minerals during the CO_2 injection period. After CO_2 injection has ceased, however, continued precipitation of calcite and other minerals over an extended period (100+ years) may indeed play a key role in retaining a large fraction of carbon atoms permanently in the reservoir.

2.2 Site Geology and Hydrology

The approximate 31,000 acres leased for the Pelican Sequestration Hub are ideally located in a structurally stable location in the Gulf of Mexico onshore basin (Section 2.0 Site Characterization

Narrative). Saline aquifers of the Oligocene Frio and Anahuac formations were penetrated by few wells, which indicates an ineffective petroleum system. This is likely due to the lack of trapping mechanisms and immature source-rock interval. Surrounding the acreage are a number of oil and gas fields that target deeper petroleum systems (Wilcox and Tuscaloosa). This provides ample data to constrain rock properties. Section 2.1.3 *Local Geology* in the Narrative document of this permit highlights the data used to constrain the local geology and hydrology.

The Oligocene Storage Complex consists of the Vicksburg formation basal seal, Frio and Lower Anahuac storage intervals, and the Upper Anahuac top seal. Details about these units and how properties were distributed in the modeling effort are documented in the following sections of the Narrative document: 2.1 *Regional Geology, Hydrogeology, and Local Structural Geology*, 2.2 *Maps and Cross Sections of the AoR*, 2.3 *Faults and Fractures*, 2.4 *Injection and Confining Zone Details*, and 2.5 *Geomechanical and Petrophysical Information*.

2.3 Model Domain

The project team conducted a detailed reservoir characterization study to address CO₂ injection and migration through the saline aquifer and constructed a geologic model using SLB Petrel (v2023). The static model is based on the collaborative interpretation of a diverse collection of geological, geophysical, and petrophysical data that was acquired from public databases, published literature, in-house studies, and in-house 3D seismic data.

The model grid covers an approximately 314 square-mile area of interest (AOI) shown as the green polygon in Figure AoR-1. This model was created using a pillar-grid type model with a lateral resolution of 500 ft X 500 ft size, which is aligned in a north-south and east-west direction. This lateral resolution adequately captures variability in the fluvio-deltaic and seismic dataset. The vertical resolution of the static model is approximately 4 ft, closely capturing log dataset inputs, and is represented by I:214 x J:188x K:909. To reduce computational time for the dynamic multiphase simulation model represented by I:214 x J:188 x K:179, the static model was vertically upscaled to the target of 10 ft. Also, it excluded shallow stratigraphic intervals not currently in the scope of the CO₂ injection program. Table AoR-1 and Table AoR-2 show the static geological model and dynamic multiphase flow model domains, respectively.

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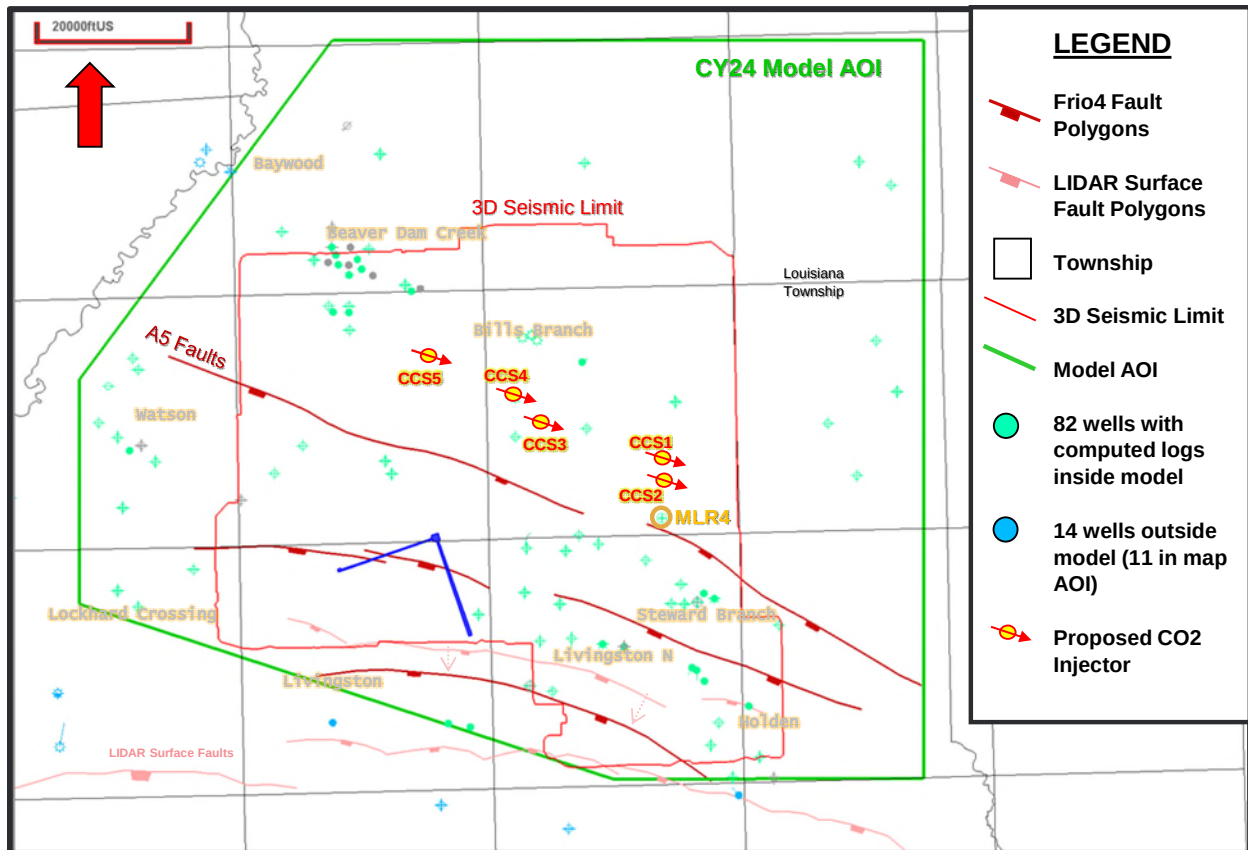


Figure AoR-1—Pelican CCS development map: well and seismic dataset.

Table AoR-1—Static geological model domain information.

Coordinate System	NAD 1927 BLM Zone 15N		
Horizontal Datum	GCS North American 1927		
Coordinate System Units	Ft US		
Zone	BLM Zone 15N		
FIPZONE	1702	ADSZONE	4051
Coordinate of X min	2295026	Coordinate of X max	2403128
Coordinate of Y min	11067485	Coordinate of Y max	11163847
Elevation of top of domain	-2,846	Elevation of bottom of domain	-8,973

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Table AoR-2—Dynamic multiphase flow model domain information.

Coordinate System	NAD_1927_BLM_Zone_15N		
Horizontal Datum	GCS North American 1927		
Coordinate System Units	Ft US		
Zone	BLM Zone 15N		
FIPZONE	1702	ADSZONE	4051
Coordinate of X min	2295026	Coordinate of X max	2403002
Coordinate of Y min	11067485	Coordinate of Y max	11163005
Elevation of top of domain	-4,145	Elevation of bottom of domain	-8,973

The methodology for the static geomodel was to capture the large-scale features first, followed by modeling progressively smaller and more uncertain features. The first step applied to the Pelican geomodel was to establish a conceptual structural and depositional model, as well as its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, net sand, and other properties.

Figure AoR-1 displays the locations of the five wells for which the Pelican Sequestration Hub, LLC, is applying for the Class VI injection permits. Also shown is the location of the stratigraphic well, Pelican MLR 004, which has been drilled to gather key reservoir and performance data to support this supplication.

2.3.1 Model Structural Framework

The Pelican development represents a typical monoclinial structure for saline-aquifer development that dips gently about 1.5° toward the SSW, hence the CO₂ plume is expected to migrate updip from the injection wells. Overall, the structural dip is relatively uniform with no significant faults or salt diapirs within the targeted area of investigation or inside the leased acreage. Upon leasing the pore space, approximately 137 square miles of 3D seismic data was licensed, covering the entire area of the leased pore acreage, as shown in Figure AoR-1. The 3D survey was acquired by Yuma Exploration in 2009 and processed by CGG Veritas. Details of the seismic data and interpretation are described in *Section 2.3.1 Local Structure and Faulting* of the Narrative document.

Major faults trending in the east-west direction were interpreted over the 3D seismic data and extended outside the 3D coverage integrating 2D seismic and active surface faults in the south area of the model domain, as shown in the Figure AoR-2. The faults trending in the east-west direction follow the major Gulf Coast regional present-day SH_{max} orientation. All faults dip to the southwest, hence the grid pillars roughly align to general fault plane dips. Most faults are vertically terminating and/or show extremely low throw offsets within the target CO₂ storage unit inside the model boundary and are not considered to hinder the flow of CO₂. The southernmost fault MAS06 is recognized as an active surface fault with offsets found in the Lower Miocene in the 3D seismic data. Details of faults interpretations can be found in *Section 2.0 Site Characterization* of the

Narrative document. A substantial portion of the Pelican Sequestration Hub, LLC's leased acreage area does not show faults cutting up through the Anahuac level.

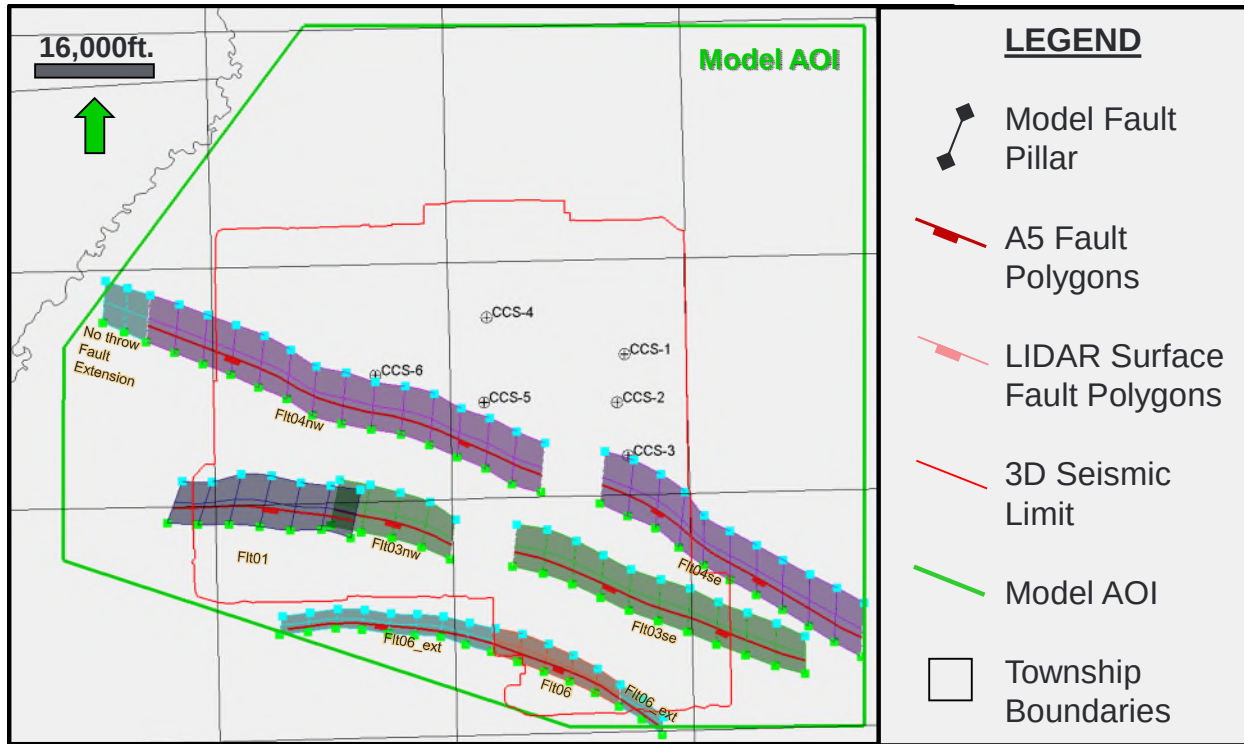


Figure AoR-2—3D Orthographic top view showing key fault pillars in static model grid.

The 3D seismic dataset fully covers Pelican Sequestration Hub, LLC's leased acreage; however, interpreted seismic horizons did not cover the entire model extents. Therefore, the structural surfaces were extrapolated using well tops in the model area.

Five key seismic horizon events that provide structural framework control for the static model are marked with red arrows in the Pelican MLR 004 type well: MMOCN2, ANAH1, ANAH3, ANAH5, and FRIO4. Differences in seismic depths were examined using the corresponding well tops and corrected before incorporating into Petrel's Horizon Modeling process and are shown in Figure AoR-3.

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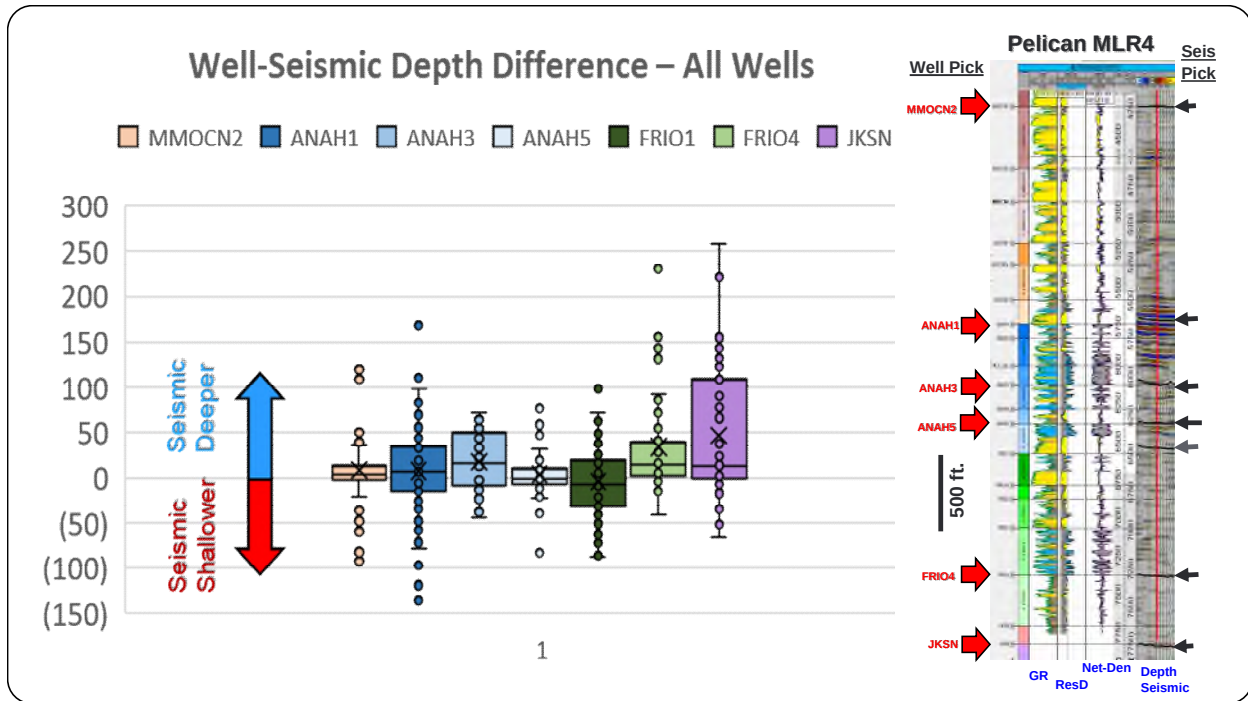


Figure AoR-3—Seismic to well pick differences.

Five seismically derived framework model structure surfaces (MMOCN2, ANAH1, ANAH3_Top, ANAH5_Top, and FRIO4_Top) are shown in Figure AoR-3 with relevant well control posted, which were used to tie seismic horizons. The ANAH5 structure serves as a high-confidence seismic pick that provides structural control to the Oligocene injection targets. These surfaces, along with faults, were then used to construct 3D model horizons, as shown in Figure AoR-4. The pillar grid has all fault planes extrapolated vertically through the entire grid. However, within the Petrel Horizon Mapping, if a fault was not identified over the seismic data (e.g., Anahuac and Miocene intervals), it is set inactive, so that no throw artifacts are created through modeling.

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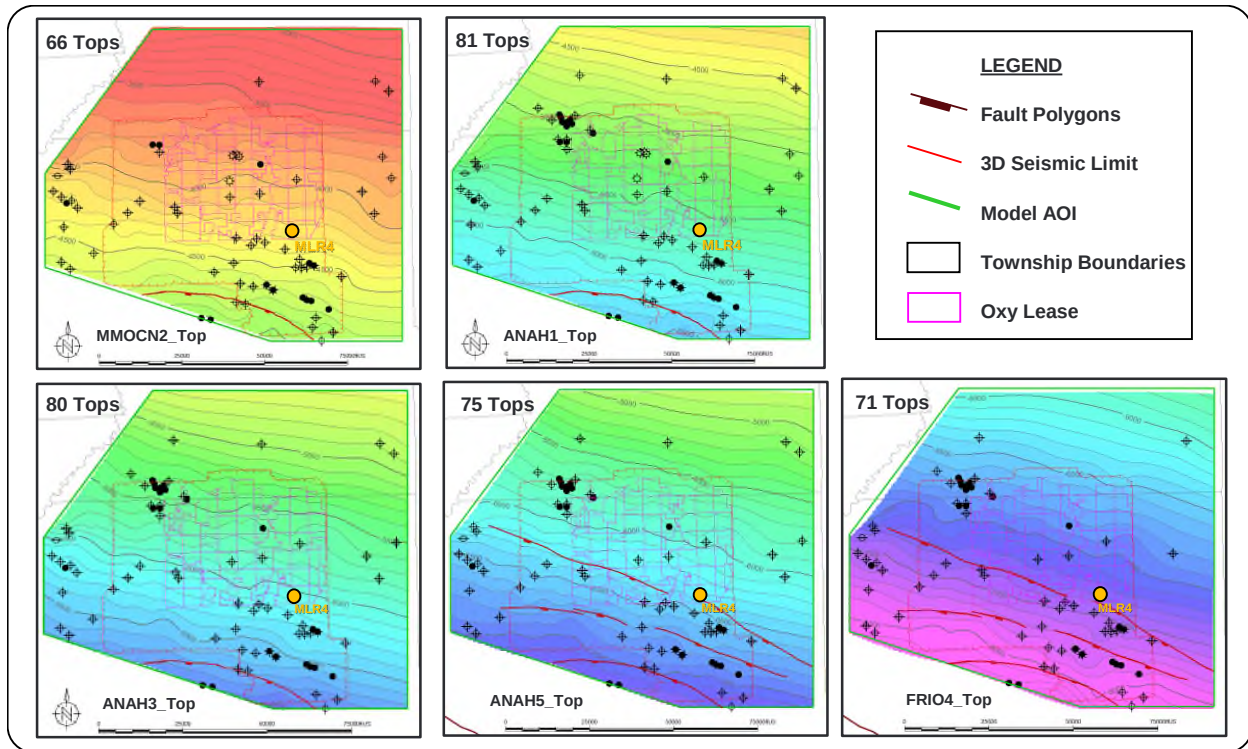


Figure AoR-4—3D model horizons and well tops.

2.3.2 Model Zones

Well picks were correlated from a multitude of well logs, including both depth-registered image logs and digital logs for the 82 wells to provide added control to well thickness mapping. Figure AoR-5 and Figure AoR-6 show the stratigraphic section north to south and west to east traverses through the model wells, respectively. In each of these two figures, vertical green-red shaded bars represent the model zone pick correlation confidence and a star represents the stratigraphic well Pelican MLR 004. Limestone beds identified on the well log motif in the Anahuac and Frio formations are laterally extensive, providing key confidence to the zone marker correlations.

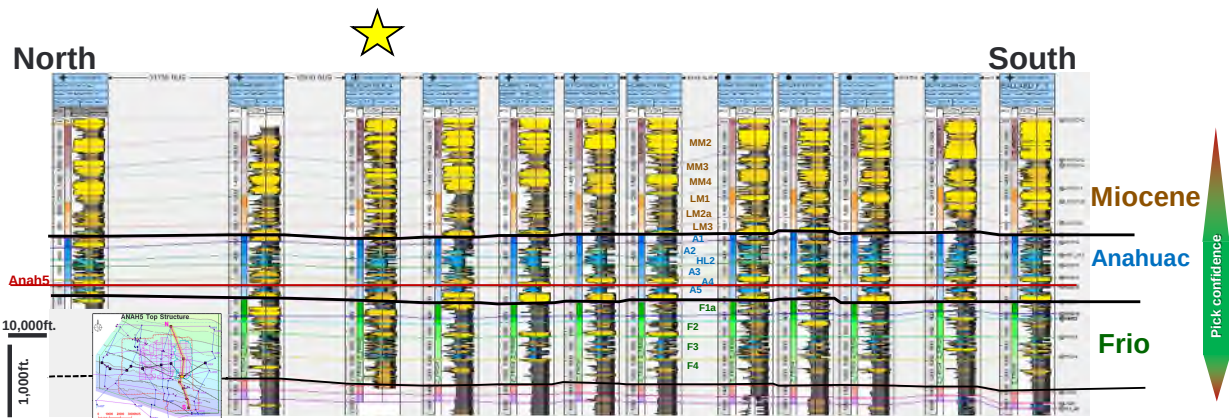


Figure AoR-5—North-south stratigraphic well section - datum = ANAH5_top.

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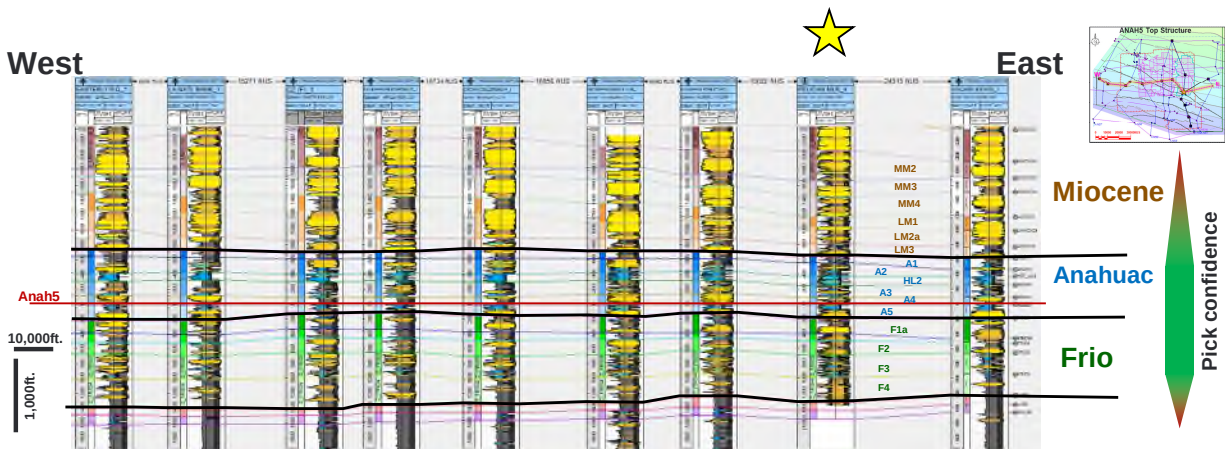


Figure AoR-6—West-east stratigraphic well section - datum =ANAH5_top.

The static model includes four major geological intervals – the Middle Miocene, Lower Miocene, Anahuac, and Frio formations. These major geological intervals, subdivided into 18 model zones for the static model, are shown in Table AoR-3. Due to the complex occurrence of various lithologies such as shale, sandstone, and limestones, our zone scheme is based on geologic-time equivalent sequence-stratigraphic picks. On this basis, the Frio formation is subdivided into four zones, namely, FRIO1a, FRIO1b, FRIO2, FRIO3, and FRIO4, while the overlying Anahuac formation is subdivided into six zones: ANAH1, ANAH2, HL2, ANAH3, ANAH4, and ANAH5. The HL2 and V zones serve as upper and lower confining zones, defining dynamic model limits.

Figure AoR-7 depicts the geologic zones on a N-S cross section through the geologic model, which was built with an average grid cell size of 500 ft × 500 ft. The 2D well-based thickness maps for each zone were separately prepared and inputted into the Petrel Zone modeling process in such a way that those are stretched and squeezed between seismically derived framework horizons, as most of the zones are observed across the model area.

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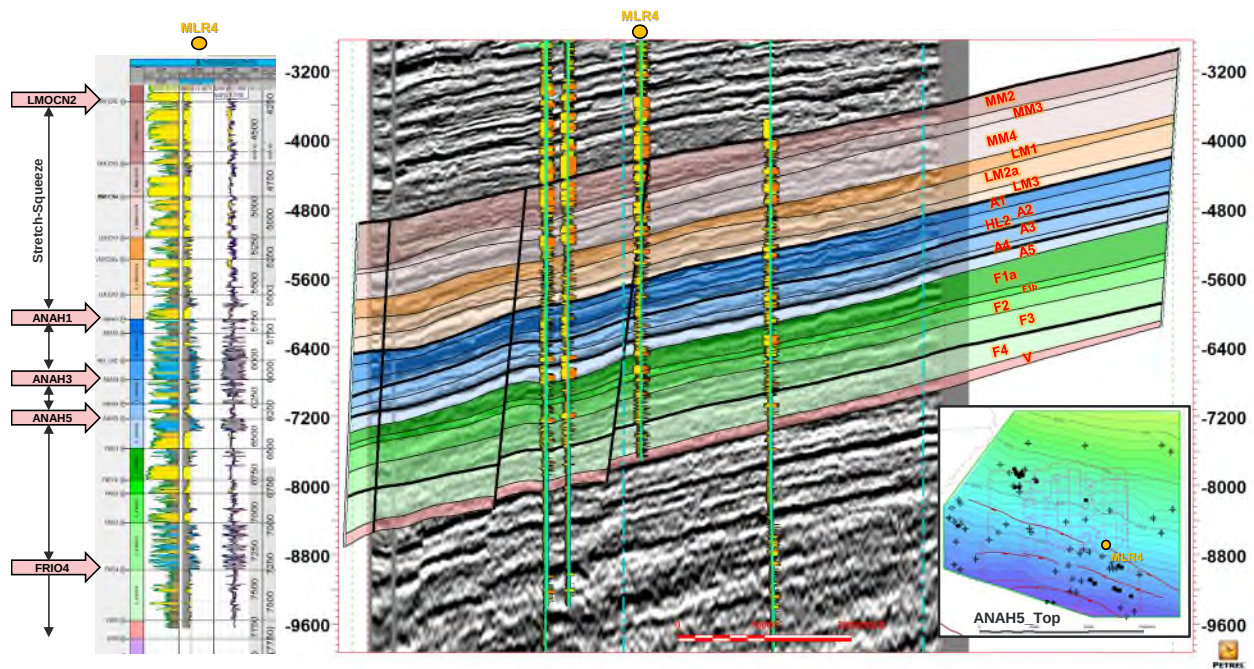


Figure AoR-7—Petrel zones and thickness treatment.

2.3.3 Model Layering and Upscaling

Proportional layering was applied to each zone with a layer thickness of 4 ft to better capture the log resolution needed for the static geological model. This static model is represented by I:214 × J:188 × K:909 index, for a total of ~40 million grid cells. A fence diagram of the eighteen zones is shown in Figure AoR-8.

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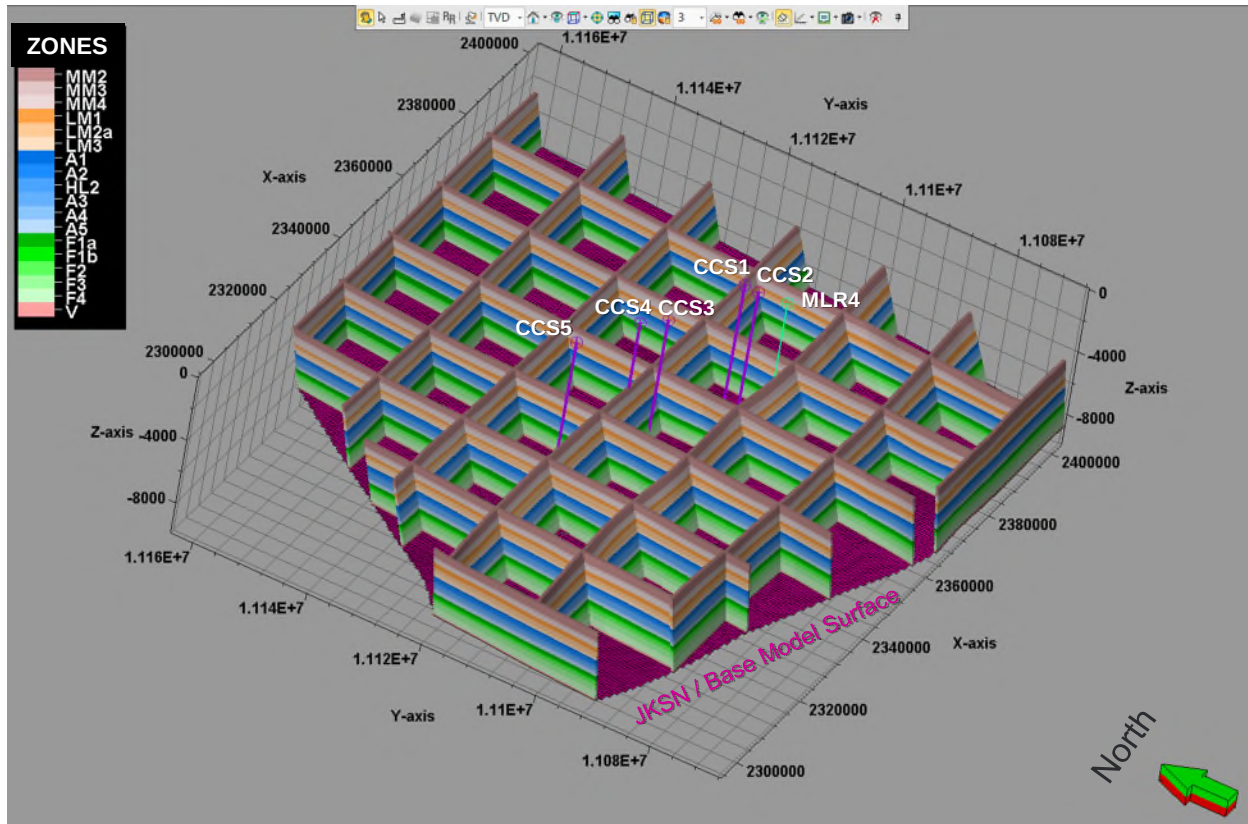


Figure AoR-8—A 3D fence diagram showing all geologic model zones.

The dynamic model grid was generated from the static model by lumping the static model vertical layers to a total of 179 layers with a target thickness of about 10 ft and for a total number of approximately 7.4 million cells for the Anahuac and Frio Injection Zones.

The number of layers in each zone for both static and dynamic grids are listed in Table AoR-3 which shows net reservoir property averages for porosity and permeabilities for all injection and confining zones. Confining unit properties are described separately in section 2.5.1 Petrophysics of the Narrative document.

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Table AoR-3—Summary of static and dynamic model zones, reservoir properties and layering.

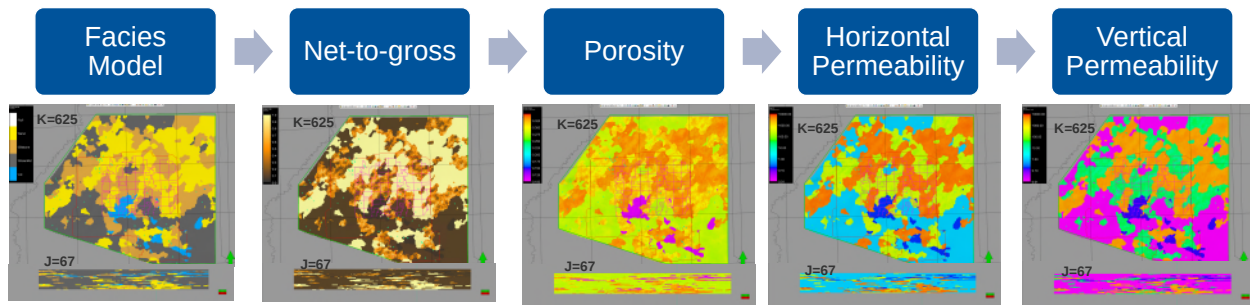
Formation	Model Zone Name	Storage Element	Top Avg. TVDSS (ft)	Base TVDSS (ft)	Avg. Dip (deg)	Avg. Dip Azi (deg)	Gross TVT (ft)	Net TVT (ft)	Net PorT (frac)	Net K _{air} (md)	Static No. of Layers	Dynamic No. of Layers
Middle Miocene	MM2		-3,964	-4,309	1.4	190	339	249	0.327	4,032	97	n/a
	MM3		-4,309	-4,459	1.5	191	146	80	0.323	3,599	37	n/a
	MM4		-4,459	-4,778	1.4	190	312	197	0.325	3,779	73	n/a
Lower Miocene	LM1		-4,778	-4,976	1.4	189	193	82	0.321	3,374	52	n/a
	LM2a		-4,976	-5,210	1.5	189	228	144	0.325	3,765	57	n/a
	LM3		-5,210	-5,382	1.5	190	168	81	0.321	3,469	46	n/a
Anahuac	A1		-5,382	-5,496	1.5	190	111	29	0.309	2,449	26	n/a
	A2		-5,496	-5,671	1.5	190	170	51	0.310	3,090	47	n/a
	HL2	Confining	-5,671	-5,780	1.5	192	106	12	0.244	2,449	29	12
	A3	Injection	-5,780	-5,985	1.5	192	200	53	0.307	2,773	48	19
	A4	Injection	-5,985	-6,091	1.5	193	103	54	0.323	3,667	28	11
	A5	Injection	-6,091	-6,243	1.6	193	148	50	0.311	3,262	42	17
Frio	F1a	Injection	-6,243	-6,496	1.5	193	248	85	0.316	2,845	54	22
	F1b	Injection	-6,496	-6,583	1.5	192	84	19	0.307	2,082	23	9
	F2	Injection	-6,583	-6,778	1.5	193	191	68	0.317	2,773	50	20
	F3	Injection	-6,778	-7,090	1.6	194	303	83	0.307	2,688	78	31
	F4	Injection	-7,090	-7,433	1.7	194	331	69	0.307	1,955	92	37
Vicksburg	V	Confining	-7,433	-7,548	1.8	194	113	12	0.283	108	30	1

2.4 Porosity and Permeability

The Injection Zone comprises fluvial-deltaic Frio and Anahuac formations that are high-porosity, high-permeability sand layers with intermittent limestones and intra-shale layers. Porosity and permeability properties are constrained by discrete facies model, which provides primary control in propagating the observations and interpretations made at the wellbores. Rock classification and petrophysical properties were calibrated to the stratigraphic well data collected in the Pelican MLR 004 well. Facies logs were upscaled and propagated into the 3D grid using a Sequential Indicator Simulation (SIS) algorithm, conditioned by probability trend maps capturing depositional trends and seismic observations. Total porosity logs were upscaled and distributed using a Sequential Gaussian Simulation (SGS) algorithm, constrained by lithofacies. Permeability functions for each facies were established from the Pelican MLR 004 core data and applied to the model cells using model porosity. The petrophysical analyses of 82 wells inside the model boundary were used to propagate the 3D distribution of petrophysical properties between the wellbores.

Figure AoR-9 summarizes the property population workflow used for the static model. The process details are described below.

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**Figure AoR-9—Reservoir property modeling workflow.**

2.4.1 Facies Modeling

Core data collected from the stratigraphic well Pelican MLR 004 was carefully examined and categorized into four key lithology classes, namely sands, silty sand, shale, and limestone, as shown in Table AoR-4. The facies log was interpreted in all 82 wells inside the model boundary to provide key control to the facies modeling.

Table AoR-4—Facies code and variogram parameters.

Code	Facies	Geological Facies Associations	Energy type	Major Range [ft]	Minor Range [ft]	Vertical Range [ft]	Maj/Min or Ratio	Zone Specific Variogram Orientation									
								HL2	A3	A4	A5	F1a	F1b	F2	F3	F4	
1	Sand	Channelized / Coastal to Marine	Wave/Fluvial/Tidal	12,000	8,000	15	1.5	-10	-10	-10	10	40	40	10	-15	30	
2	Silty Sand	Marine lower shoreface, Fluvial Mixed / Crevasses / Levee	Wave / Fluvial / Tidal	7,000	5,000	8	1.4	-10	-10	-10	10	40	40	10	-15	30	
3	Shale	Marine / non-marine	Low energy + Channel Fills	15,000	13,000	10	1.2	60	-80	-80	-80	-70	-70	-70	80	-65	
4	Limestone	Marine and reworked	Marine Low energy	35,000	30,000	8	1.2	60	-80	-80	-80	-70	-70	-70	80	-65	

Before populating rock properties into the 3D static geological model, the facies model was developed using the Sequential Indicator Simulation (SIS) algorithm. To guide facies propagation between well data, a hand-contoured probability trend map was constructed for each model zone from the environment of deposition (EOD) map. Furthermore, a vertical layer proportions trend was also applied from well data to reflect vertical facies variability in the model that is sensitive to CO₂ plume migration within the dynamic model. Figure AoR-10 highlights the facies modeling workflow that involves various depositional and data trends into the model area. More details of depositional settings can be found in *Section 2.4.1.2 Regional Study and Log Facies Characterization* of the Narrative document.

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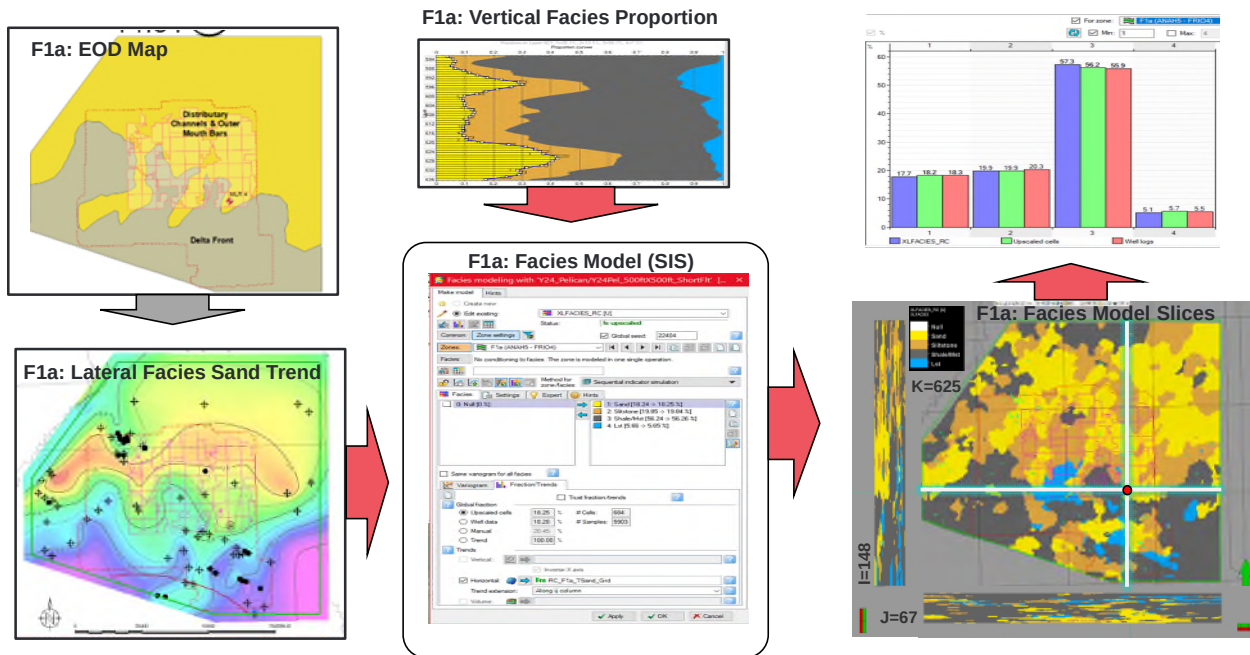


Figure AoR-10—Example SIS-based facies modeling workflow.

To populate the facies model property, a broad range of facies associations were assumed for litho-facies codes shown in the Figure AoR-11. Having these geological associations of simplified facies categories helped define the variogram parameter, which is summarized in Table AoR-4. For the primary Anahuac and Frio zones, variogram lengths were unchanged. However, the orientation of these variograms were adjusted to corresponding depositional trends. Larger variogram lengths were used for shales and limestone facies that are interpreted as marine and assumed to be laterally extensive, as observed in the well log data set. The SIS algorithms provided good control on matching output facies proportions to the well data. Additionally, these variogram ranges were varied to produce low and high cases of facies for the dynamic sensitivity analysis discussed in *3.2.1 Sensitivity to Input Parameters* to input parameters of this AoR Document.

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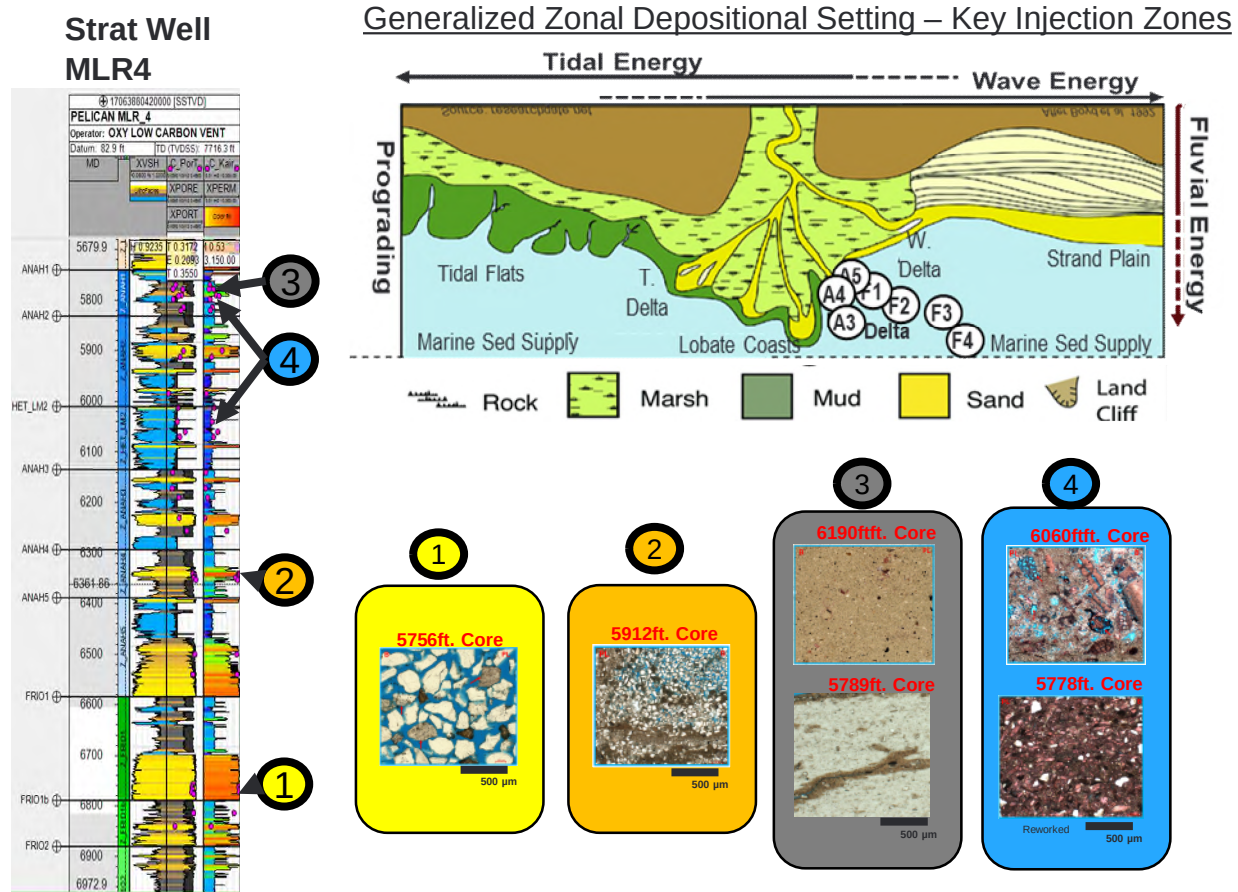


Figure AoR-11—Facies categories and generalized depositional settings.

The outcome of the facies model for Het Lime to Vicksburg is shown in Figure AoR-12

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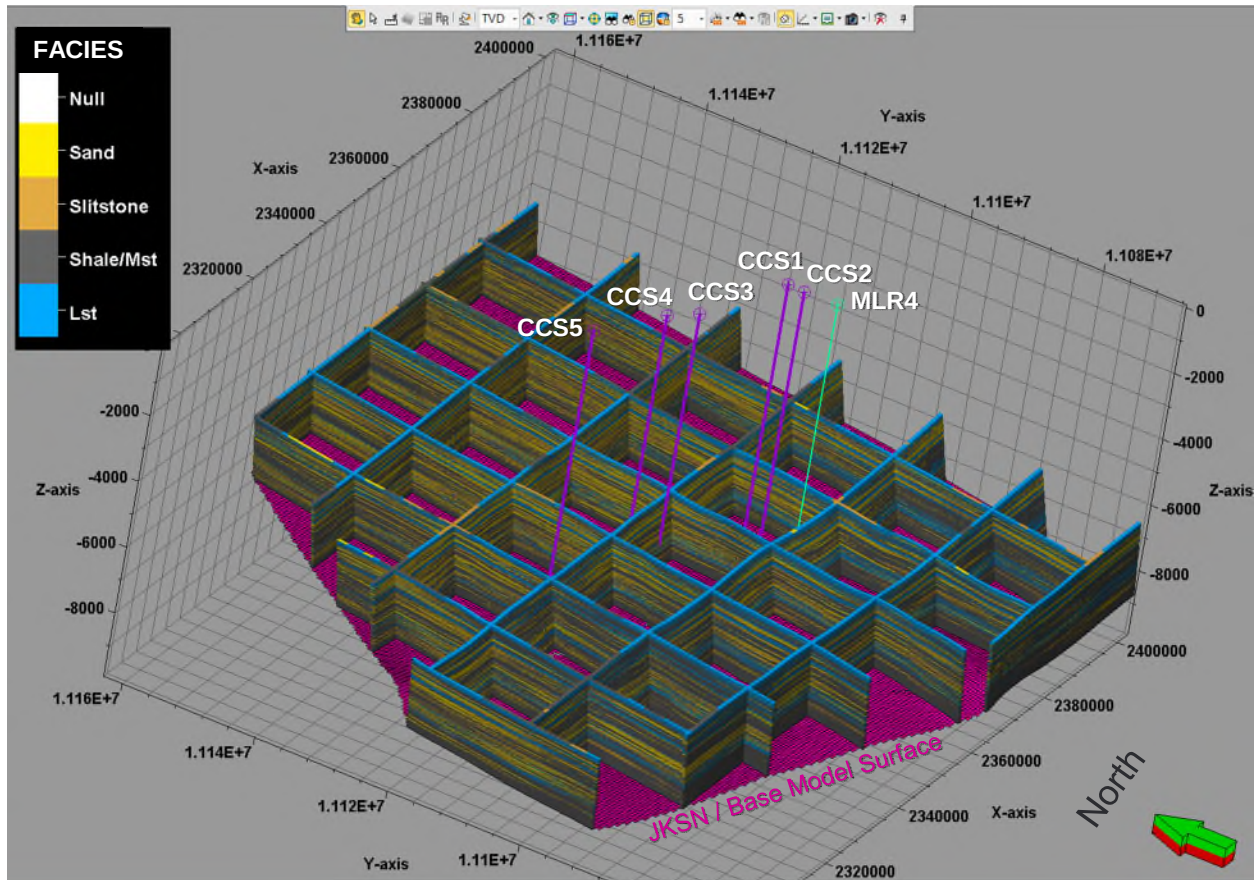


Figure AoR-12—A 3D fence diagram showing facies model.

2.4.2 Net-to-Gross

To keep integrity of the pore volume between the static and dynamic models, the net-to-gross property is defined based on facies categories. Additionally, no porosity and permeability cutoffs were used for defining net reservoir cells. Figure AoR-13 summarizes our net-to gross assumption made for the static model. Vacuum-dried porosity data collected from Pelican MLR 004 stratigraphic well was used to calibrate the total porosity. Special treatment was made for the silty sand property by using clay-volume log as proxy for the net-to-gross property. This VclNet log data was then upscaled to the 3D model cells and populated into the 3D model using facies constraint sequential gaussian simulation (SGS). The net-to-gross properties for non-reservoir rocks like shale and limestone with little CO₂ flow potential were set to non-zero with low net values to enable those cells in the dynamic model for pressure dissipation.

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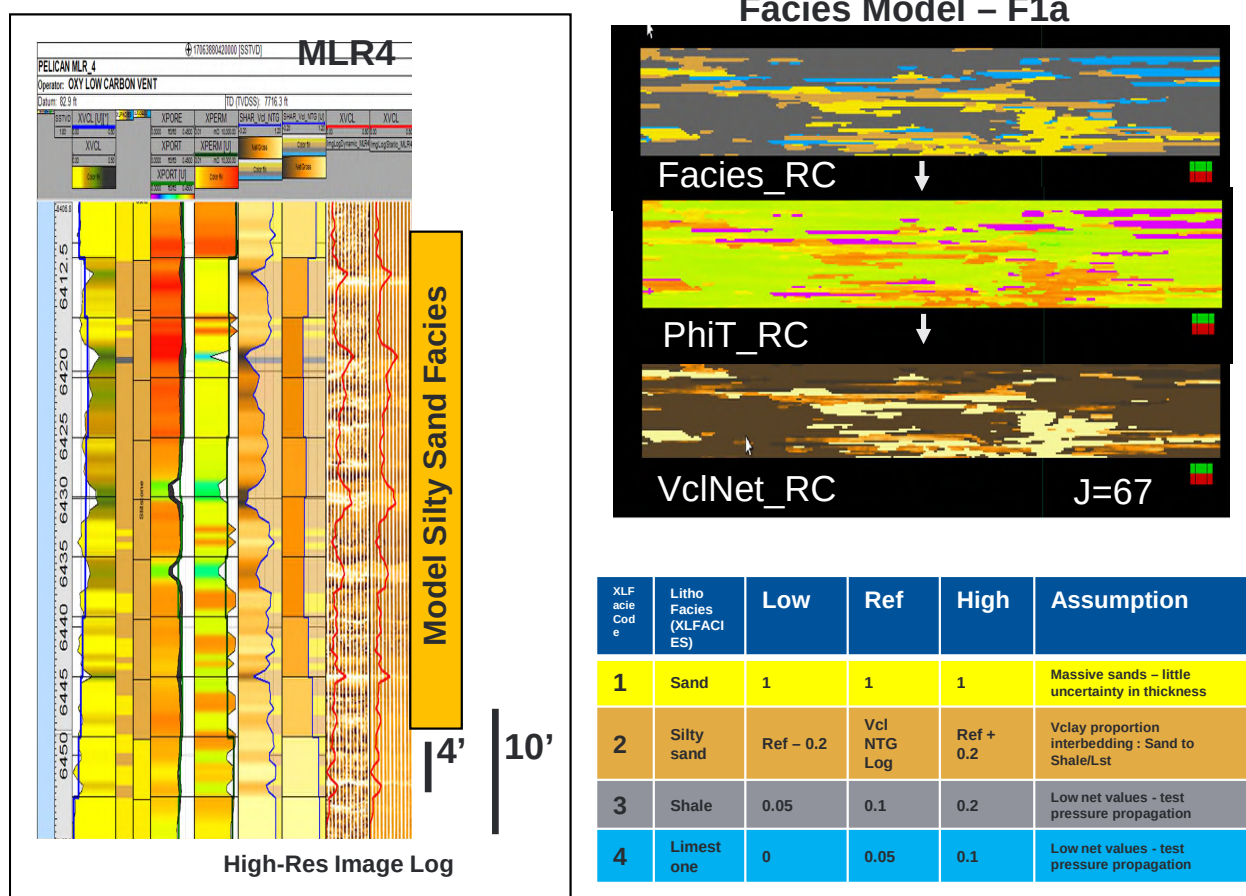


Figure AoR-13—Net-to-gross property assumption.

2.4.3 Porosity Model

The total porosity logs from wells were sampled using arithmetic averages with net-to-gross log weighting described in *Section*. Well histogram distributions were matched as input normal score transformation distributions with some smoothing applied.

The porosity property in the geologic model was populated using Gaussian Random Function Simulation (GRFS) algorithm constraint by facies model described in 2.4.1 *Facies Modeling* above, which provides overarching spatial distribution for the model cells.

Table AoR-5 summarizes the variogram parameters used for all zones except for the variogram orientation, which was defined on zone-by-zone and by facies in similar fashion than the facies variograms. Variogram lengths were reduced by half from what was used for facies to address smaller scale lateral variability in the dataset. Figure AoR-14 shows the reference case porosity model along with histogram distribution display of well log, blocked and static model cells. Model net average total porosity values are listed in Table AoR-3.

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Table AoR-5—Porosity variogram parameters.

Facies	Algorithm	Azimuth	Nugget	Type	Major	Minor	Vertical	Sill	Trend extension	Method	Sec. prop. transform
1: Sand	GRFS	40	0	Spherical	6,000	4,000	8	1	Vertically	LVM	Normal score
2: Siltstone	GRFS	40	0	Spherical	3,500	2,500	8	1	Vertically	LVM	Normal score
3: Shale/ Mudstone	GRFS	-70	0	Spherical	7,000	6,500	8	1	Vertically	LVM	Normal score
4: Limestone	GRFS	-70	0	Spherical	17,500	15,000	8	1	Vertically	LVM	Normal score

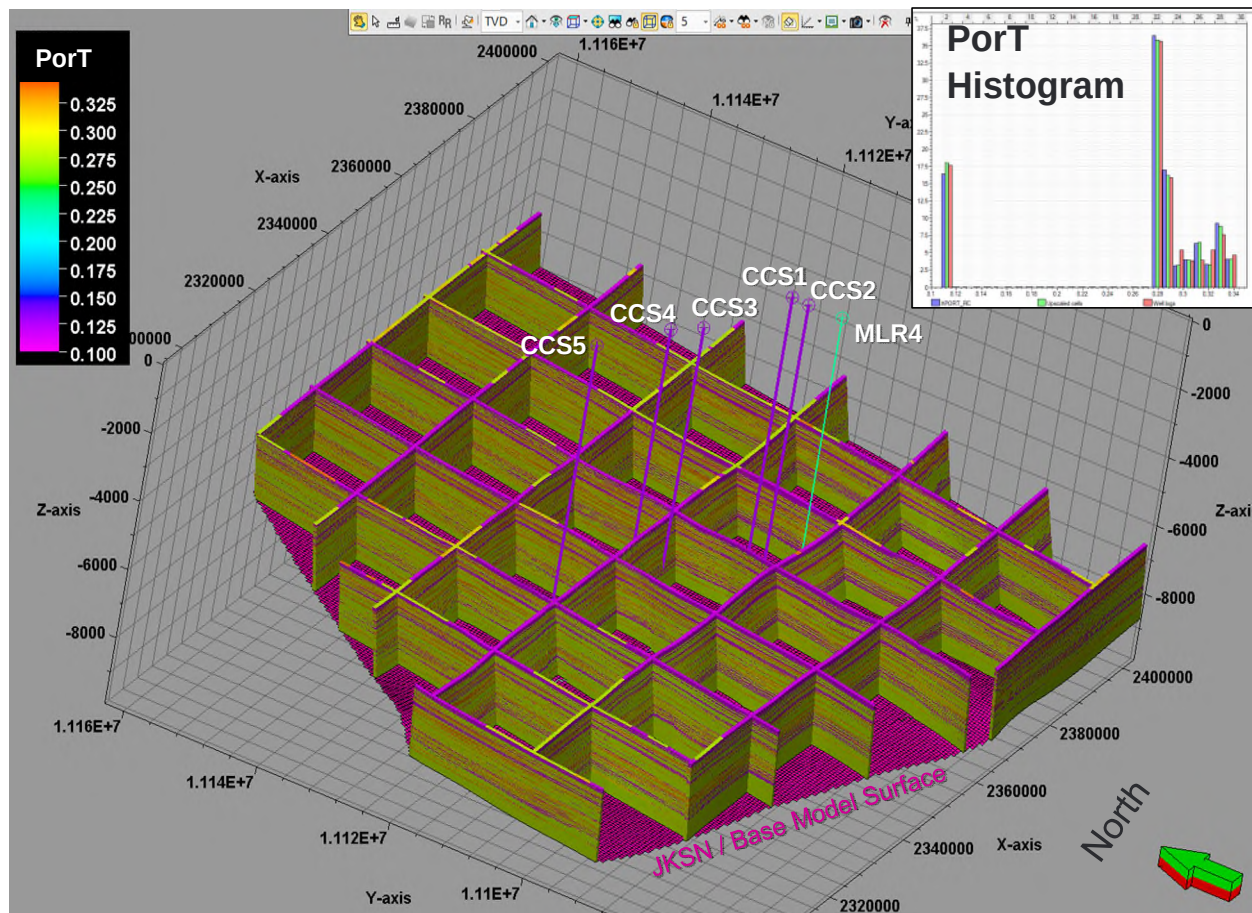


Figure AoR-14—A 3D fence diagram showing model total porosity.

2.4.4 Permeability

The horizontal permeability for the Injection Zones was based on data collected and analyzed from the stratigraphic well Pelican MLR 004. Vacuum-dried core samples, which represent log-derived total porosity, are shown in Figure AoR-15 along with the resultant permeability property in the static model. Core porosity-permeability transforms were developed for each of the four facies classes: sand, siltstone, shale/mudstone, and limestone. Those transforms were directly applied in

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the fine-scale stratigraphic model using total porosity property to reproduce permeability values for entire model cells. All zones use the same perm transforms in the model. Figure AoR-16 shows a 3D fence diagram for the horizontal permeability property along with histogram distribution calculated from the porosity in the static model grid.

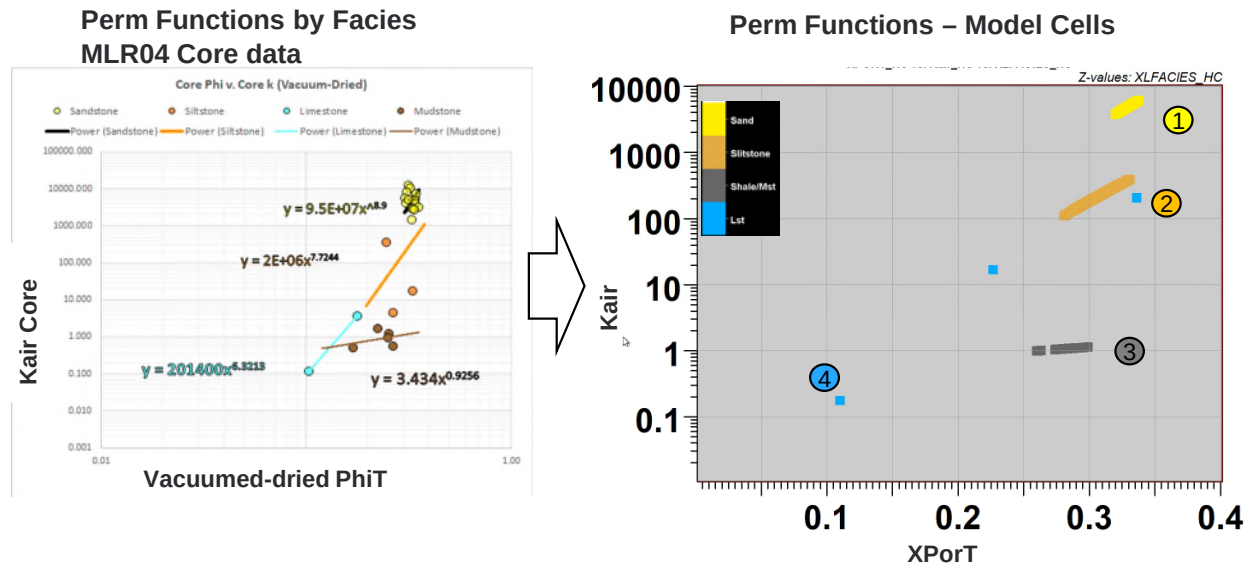


Figure AoR-15—Permeability-porosity transform fit to core data.

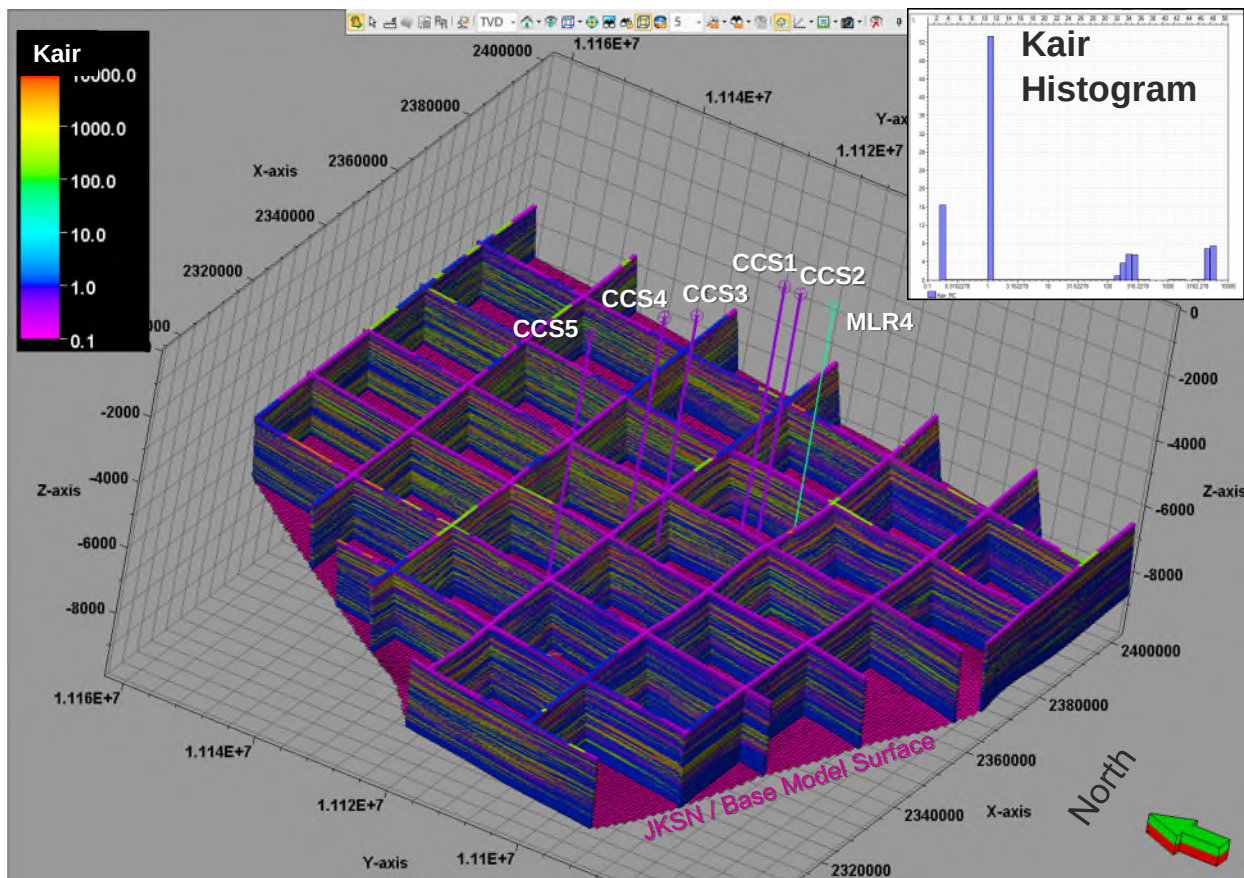


Figure AoR-16—3D fence diagram showing model Horizontal Permeability.

The vertical permeability was calculated by assuming a generalized K_v/K_h set of values for each facies class using the horizontal permeability property described above. Vertical permeability is a highly scale-dependent property, which influences plume migration in the dynamic model. Generalized K_v/K_h ratios were used to represent close to log-scale resolution captured in the fine-scale model, as shown in Table AoR-6. Sandstone facies have a high K_v/K_h ratio of 0.6 due to a massive character observed in well logs and is supported from the core data acquired in the Pelican MLR 004 stratigraphic well. Due to the interbedded nature of Siltstone facies, special consideration was made to reduce K_v/K_h ratio down to 0.1. Shale facies with clay-rich interbedding have the lowest K_v/K_h ratio. Limestone facies have very low horizontal perm and porosity values; however, those limestone facies show no organized layering, hence the K_v/K_h is set to highest value, which makes limestone facies a very strong baffle to flow. The resultant vertical perm property from the K_v/K_h ratios was upscaled to the dynamic model grid at close to 10 ft vertical resolution.

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Table AoR-6—Kv/Kh ratio assumptions.

XLFacies Code	Litho (XLFACIES)	Kv/Kh	Comments
1	Sand	0.6	Massive Character – minor thin shale beds
2	Silty sand	0.1	Often interbedded
3	Shale	0.01	Some silty interbedding
4	Limestone	0.8	Skeletal limestone disorganized

2.4.5 Upscaling Properties to Dynamic Model Grid

The fine-scale static model properties (represented by I:214 x J:188 x K:909) were upscaled to the dynamic model layers (represented by I:214 x J:188 x K:179). The net-to-gross property was calculated using a simple arithmetic averaging method. Total porosity and horizontal permeability properties were weighted with the net-to-gross property. Figure AoR-17 shows pore volumes compared over the entire model volume, which demonstrates good integrity of properties between two model grids.

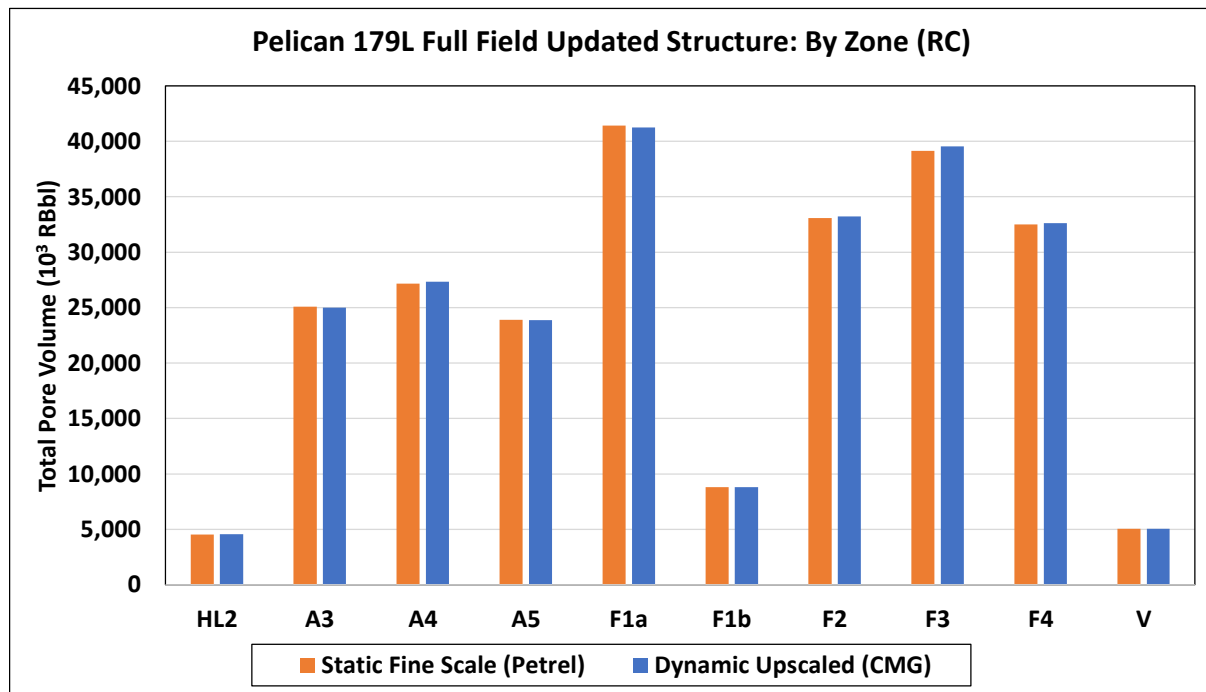


Figure AoR-17—Pore volume comparison static and dynamic model grids.

Vertical permeability in the dynamic model was upscaled by using harmonic averages with no net-to-gross weighting, which reflects the baffled impact to vertical flow in the dynamic model.

2.5 Constitutive Relationships and Other Rock Properties

All simulations runs were executed using the GEM simulator, as outlined in Section 2.1. The grid properties of porosity, horizontal permeability, and vertical permeability were directly imported from the static geomodel. The base vertical permeability (K_v) for each grid cell was calculated using the specified K_v/K_h ratio.

The water-gas relative permeability curves and capillary pressure data were constructed from analysis of available lab data from the Pelican MLR 004 (SN: 975950/API: 17063880420000). Permeability curves and capillary pressure data were used for the four facies as identified from the petrophysical analysis. Endpoint values and Corey exponents used in modeling are from lab data analysis and shown in Table AoR-7.

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Table AoR-7—Endpoint values and Corey exponents from lab data analysis.

Data	Sandstone	Siltstone	Mudstone	Limestone
Pc,max (psi)	126	256	2,500	2,500
Irreducible Water Saturation, Swirr	0.07	0.15	0.50	0.34
Critical gas Saturation, Sgc	0.05	0.08	0.08	0.08
Trapped gas Saturation, Sgt	0.15	0.30	0.40	0.40
krw (at 100% Sw)	1	1	1	1
kr_g (at Swirr)	0.55	0.40	0.06	0.07
Corey Exponent For Water, Nw	4.50	5.77	3.37	3.45
Corey Exponent For Gas, Ng	3.50	3.77	1.37	1.45

All dynamic simulation runs included relative permeability hysteresis and curves for drainage and imbibition capillary pressure. During the imbibition cycle (water displacing gas), trapped gas saturation (Sgt) values depend on the maximum gas saturation (Sgh) of the grid block. The trapped gas saturation used for all the four facies are specified in Table AoR-7. These values were estimated from available experimental data available at the time of the model construction. These values are consistent with the values previously reported, by Ghomian (2008), Bachu (2013), Benson et al. (2013), and Likanapaisal et al. (2023).

2.6 Boundary Conditions

Boundary conditions and limits of the saline aquifer play a key role in modeling pressure propagation and dissipation in the dynamic model. The no-flow boundary condition considered for overlaying Het Lime (HL2) impermeable zone and underlying Vicksburg of the model assumes that these confining units are continuous throughout the region. The Oligocene Storage complex is laterally extensive in the Gulf Coast region as shown in Figure AoR-18, although there is some uncertainty about effective hydraulic connectivity over such a large distance.

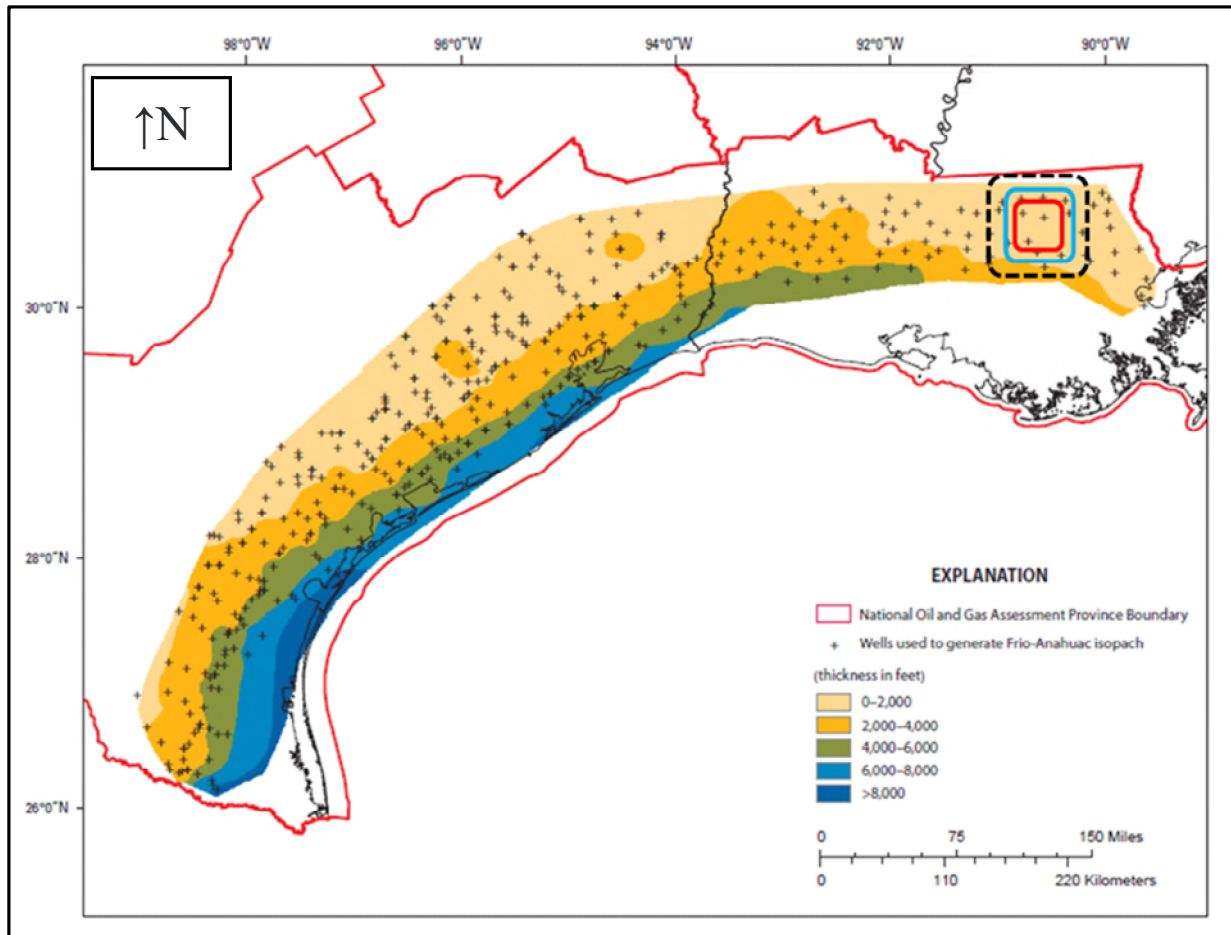


Figure AoR-18—Map showing Frio sand thickness in the Gulf Coast area.

To capture volumetric uncertainty, aquifer pore volumes were estimated through mapping 2D pore thickness cases coupled with areal polygons with considerations defined by geological and/or pressure boundaries. Pore thickness from the model area was extrapolated regionally using GCCC Oligocene regional pore thickness map. Three deterministic cases (Low, Reference, and High) of pore volume estimated by varying thickness and areal limits of the aquifer to appropriately represent the uncertainty shown in Figure AoR-19.

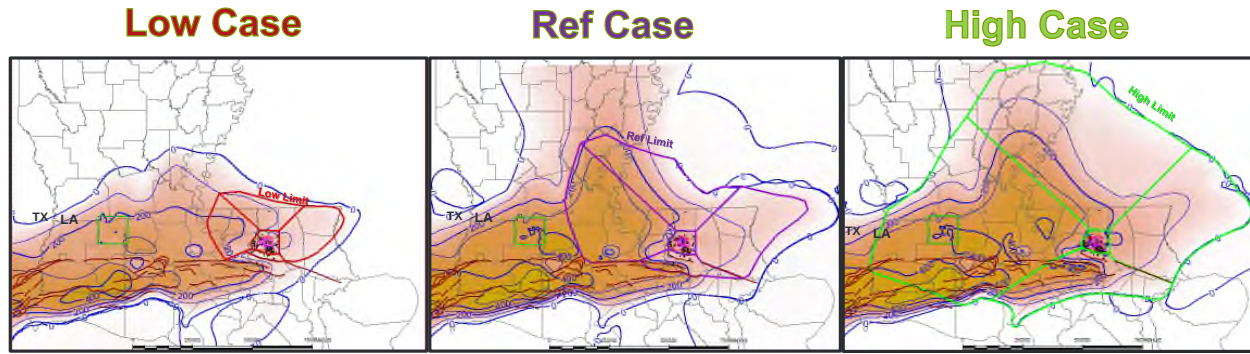


Figure AoR-19—Aquifer thickness and extent range.

To quantify its impact on AoR predictions, the horizontal boundary conditions were analyzed as a sensitivity parameter in the dynamic simulation model. The estimated aquifer pore volumes at each side of the boundary were captured numerically in the GEM dynamic simulation model by increasing the pore volume of the outermost ring of cells adjacent to the horizontal boundaries. Two rows of aquifer volume cells were defined and allocated in such a way that the outer boundary strip has approximately 90% and inner boundary strip has approximately 10% of the aquifer pore volumes.

2.7 Initial Conditions

Table AoR-8 summarizes initial conditions used for the multiphase flow model.

Table AoR-8—Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	94.5 172	°F	-3,000 -8,000	MDT data, Pelican MLR 004 well
Reservoir pressure gradient (psi/ft)	0.445	psi/ft		MDT data, Pelican MLR 004 well
Formation pressure	2,225	psi	-5,000 ft	MDT data, Pelican MLR 004 well
Fluid density	63.86	lb/ft ³	-6,707 to -6,716 ft MD	MDT data, Pelican MLR 004 well
Salinity	115,000	ppm	-6,707 to -6,716 ft MD	MDT data, Pelican MLR 004 well

In this study, initial conditions for reservoir pressure were determined using a regional hydrostatic pressure gradient of 0.445 psi/ft. For the modeled pressure gradient within the Injection Zone, a water density of 63.86 lb/ft³ (brine with 115,000 ppm total dissolved solids) was specified based on produced water analysis collected at the Pelican MLR 004 stratigraphic well.

2.8 Operational Information

The model was initialized with hydrostatic conditions and run without active wells, modeling 8 years to ensure equilibrium and no fluid movement. The base-case model run for each injection

well continued for another 100 years post-injection to simulate CO₂ migration after post-injection site closure.

In the Eastern lease contains two injection wells, Pelican CCS 1 and CCS 2. In Year 0, the Pelican CCS 1 well begins injecting with a primary rate constraint of 105 MMscfd (2.0 MMTPA). A secondary bottomhole pressure (BHP) constraint of 4,750 psia (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft) is set at the well reference depth of 6,768 ft total vertical depth subsurface (TVDSS). The injection stream composition is 100% CO₂. At the same time, Pelican CCS 2 begins injecting with the same composition and rate constraint of 105 MMscfd (2.0 million mta) and a BHP constraint of 4,475 psia at 6,366 ft TVDSS (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft). Both wells continue injection for 25 years. The injection target zones for CCS 1 well are the FRIO3 and FRIO4 zone for 8 years. These zones will be squeezed and the well will then be recompleted for injection in the ANAH3, ANAH4, and ANAH5 zones for another 8 years. Finally, the well will again be recompleted for injection in the FRIO1a, FRIO1b, and FRIO2 zones for the remaining 9 years, resulting in a total of 25 years of continuous CO₂ injection. A similar strategy will be followed for the CCS 2 well. The injection target zones for CCS 2 well will be the FRIO1a, FRIO1b, and FRIO2 zones for 8 years, the FRIO3 and FRIO4 zones for 8 years, and the ANAH3, ANAH4, and ANAH5 zones for remaining 9 years, resulting in a total of 25 years of continuous CO₂ injection.

The Center lease contains two injection wells, Pelican CCS 3 and CCS 4. In Year 0, the Pelican CCS 3 well begins injecting with a primary rate constraint of 105 MMscfd (2.0 million mta). A secondary BHP constraint of 4,075 psia (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft) is set at the well reference depth of 5,832 ft TVDSS. The injection stream composition is 100% CO₂. At the same time, Pelican CCS 4 begins injecting with the same composition and rate constraint of 105 MMscfd (2.0 million mta), and a BHP constraint of 4,750 psia at 6,947 ft TVDSS (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft). Both wells continued injection for 25 years. Unlike the CCS 1 and CCS 2 wells, CCS 3 and CCS 4 injection will be conducted in four sequences. The injection target zones and sequence for CCS 3 well are ANAH3/ANAH4, ANAH5/FRIO1a, FRIO1b/FRIO2, and FRIO3/FRIO4 zones for 4.0, 6.0, 4.0, and 11.0 years of injection, respectively. For the CCS 4 well, the corresponding target zones and sequence are FRIO3/FRIO4, ANAH3/ANAH4, A5/FRIO1a, and FRIO1b/FRIO2 zones for 10.0, 4.0, 6.0, and 5.0 years of injection, respectively.

The Western lease contains one injection well, Pelican CCS 5. In Year 0, the Pelican CCS 5 well begins injecting with a primary rate constraint of 105 MMscfd (2.0 million mta). A secondary BHP constraint of 3,950 psia (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft) is set at the well reference depth of 5,632 ft total TVDSS (set below the 90% of the minimum estimated fracture gradient of 0.79 psi/ft). The injection stream composition is 100% CO₂. The injection target zone for CCS 5 well was the ANAH3/A4/A5 zone for 8 years. These intervals were squeezed and the well was then recompleted for injection in the F1a/F1b/F2 zone for another 8 years. Finally, the well was recompleted for injection in the F3/F4 zone for remainder 9 years, resulting in a total of 25 years of continuous CO₂ injection. Details on the injection operation are presented in Table AoR-9.

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Table AoR-9—Operating details.

Operating Information	Pelican CCS 1	Pelican CCS 2	Pelican CCS 3	Pelican CCS 4	Pelican CCS 5
Location (global coordinates)					
Lat.	30°35'19.1539" N	30°34'53.9774" N	30°36'10.5631" N	30°36'41.0298" N	30°37'35.2580" N
Long.	- 90°40'55.7562" W	- 90°40'58.8266" W	- 90°43'50.1342" W	- 90°44'29.7151" W	- 90°46'30.2084" W
Model coordinates (ft)					
X	2369594	2369378	2354247	2350726	2340088
Y	11109302	11106753	11114185	11117193	11122462
No. of perforated intervals	3	3	4	4	3
Perforated interval #1 (ft MSL)*					
Z top	6,768	6,366	5,832	6,947	5,632
Z bottom	7,409	6,843	6,155	7,406	6,130
Recompletion interval #2 (ft MSL)					
Z top	5,862	6,843	6,155	5,750	6,130
Z bottom	6,296	7,489	6,531	6,112	6,678
Recompletion interval #3 (ft MSL)					
Z top	6,296	5,946	6,531	6,112	6,678
Z bottom	6,768	6,366	6,811	6,468	7,286
Recompletion interval #4 (ft MSL)					
Z top			7,003	6,468	
Z bottom			7,455	6,761	
Wellbore diameter (in.)*	8.4	8.4	8.4	8.4	8.4
Planned injection period					
Start	1-Jan-2029	1-Jan-2029	1-Jan-2029	1-Jan-2029	1-Jan-2029
End	1-Jan-2054	1-Jan-2054	1-Jan-2054	1-Jan-2054	1-Jan-2054
Injection duration (years)	25	25	25	25	25

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Operating Information	Pelican CCS 1	Pelican CCS 2	Pelican CCS 3	Pelican CCS 4	Pelican CCS 5
Injection rate (t/day)	5,476	5,476	5,476	5,476	5,476

*Represents Z coordinates and diameter in the model, not the final wellbore design

2.9 Fracture Pressure and Fracture Gradient

Geomechanical analysis was conducted to determine potential risks associated with changes in pore pressure caused by the CO₂ injection program and are described in *Section 2.3.3 Fault Reactivation Analysis* of the Narrative document. This analysis suggests that, under the current injection program, the formation pressure does not reach a level that would risk failure either through the confining unit or fault reactivation.

A fracture gradient of 0.79 psi/ft is applied to determine the maximum injection pressure, which was derived from the geomechanical analysis and the test results, as provided in Table AoR-10.

Table AoR-10—Injection pressure details for the shallowest completion.

Injection Pressure Details	Pelican CCS 1	Pelican CCS 2	Pelican CCS 3	Pelican CCS 4	Pelican CCS 5
Fracture gradient (psi/ft)	0.79	0.79	0.79	0.79	0.79
Perforation interval TVDSS, Shallowest Completion, top-bottom (ft)	5,862 – 6,296	5,946 – 6,366	5,832 – 6,155	5,750 – 6,112	5,632 – 6,130
Perforation interval MD, Shallowest Completion, top-bottom (ft)	5,953 – 6,387	6,034 – 6,454	5,934 – 6,257	5,858 – 6,220	5,730 – 6,228
Perforation interval TVD, Shallowest Completion, top-bottom (ft)	5,953 – 6,387	6,034 – 6,454	5,934 – 6,257	5,858 – 6,220	5,730 – 6,228
Bottomhole gauge depth MD ¹ /TVD ² (ft)	5,850	5,930	5,830	5,750	5,630
Calculated maximum injection pressure, with safety factor applied, at the top of the perforated interval (psi)	4,233	4,290	4,219	4,165	4,074

Considering the top of perforations as given in table above, the maximum bottom injection pressures at the top of perforation are calculated to be:

CCS 1: 5953 ft x 0.9 x 0.79 psi/ft = 4233 psig

CCS 2: 6034 ft x 0.9 x 0.79 psi/ft = 4290 psig

CCS 3: 5934 ft x 0.9 x 0.79 psi/ft = 4219 psig

CCS 4: 5858 ft x 0.9 x 0.79 psi/ft = 4165 psig

CCS 5: 5730 ft x 0.9 x 0.79 psi/ft = 4074 psig

3.0 Computational Modeling Results

3.1 Predictive Behavior

The dynamic simulations were carried out in 3D using full physics, an Equation of State for fluid PVT, and the full geologic model encompassing an area of 20×18 square miles. The dynamic reservoir simulation was performed with the same $500 \text{ ft} \times 500 \text{ ft} \times 10 \text{ ft}$ grid cells as those in the geologic model. The areal extent of the simulation model is shown in Figure AoR-1.

Eleven zones were imported into CMG Builder: HL2 (Het Lime), layers 1 – 12; A3 (ANAH3), layers 13 – 31; A4 (ANAH4), layers 32 – 42; A5 (ANAH5), layers 43-59; F1a (FRIO1a), layers 60 – 81; F1b (FRIO1b), layers 82 – 90; F2 (FRIO2), layers 91 – 110; F3 (FRIO3) layers 111 – 141; F4 (FRIO4), layers 142 – 178; and V (Vicksburg), layer 179. The dynamic model has a cartesian grid with dimensions $i=214$, $j=188$, and $k=219$, containing more than 6 million active cells.

The simulated well rates and pressures are shown in Figures AoR-21 through AoR-25. Wellhead pressures were calculated using a PROSPER-generated tubing table (PROSPER, 2020) with 5.5-in. tubing. The maximum BHP for each CO₂ injection well is reported in Table AoR-11 and below the operational constraint of 90% of fracture pressure at the corresponding depth. Well injection tests confirmed reservoir injection rates equivalent to 2 million tonnes per year (MMTPA) in each zone. The wellhead pressure for the injection wells predicted by the simulation model is reported in Table AoR-11. Wellhead pressures for actual operation may vary due to completion and tubing design. See Summary of Operating Conditions and Injection Well Construction Plan documentation for additional details.

The resulting maximum extents of the CO₂ plume and the pressure front are discussed in Section 4.0. The movement of the CO₂ plume and pressure front with time are shown in Section 5.3 and in the Post-Injection Site Care (PISC) Plan of this permit.

Table AoR-11—Injection well maximum bottomhole pressure (BHP) and wellhead pressure (WHP) at normal operating rate (2 MMTPA).

Well	Maximum Bottomhole Pressure (BHP), psig	Maximum Wellhead Pressure (WHP), psig
Pelican CCS 1	3,552	1,891
Pelican CCS 2	3,467	1,901
Pelican CCS 3	3,555	2,080
Pelican CCS 4	3,558	1,895
Pelican CCS 5	3,486	2,055

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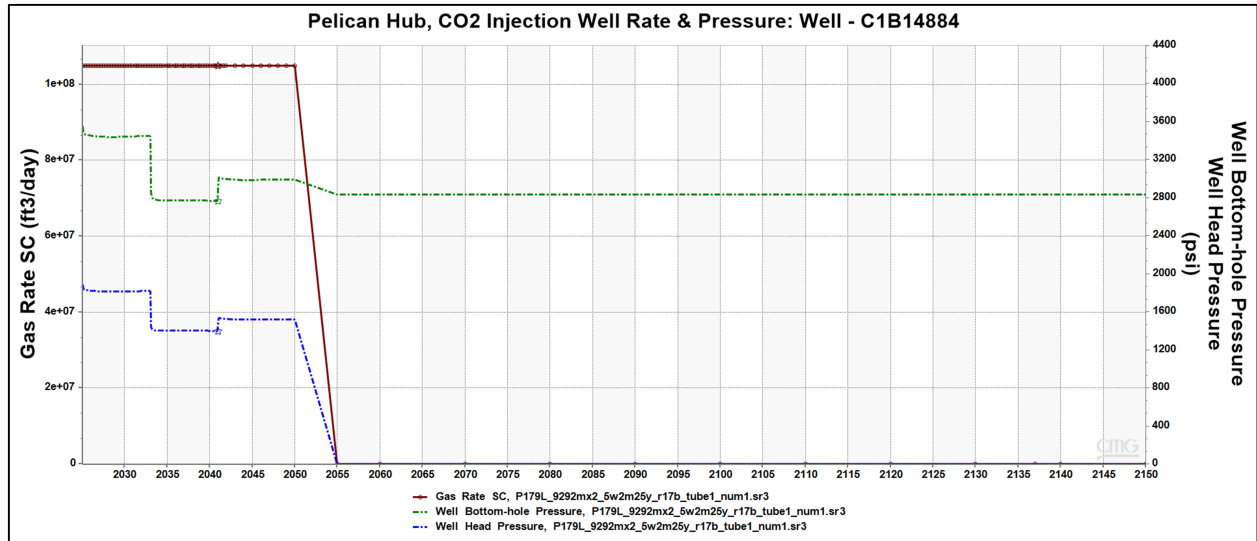


Figure AoR-20— Simulated well CO₂ injection rates and corresponding wellhead and bottomhole pressures for Pelican CCS 1.

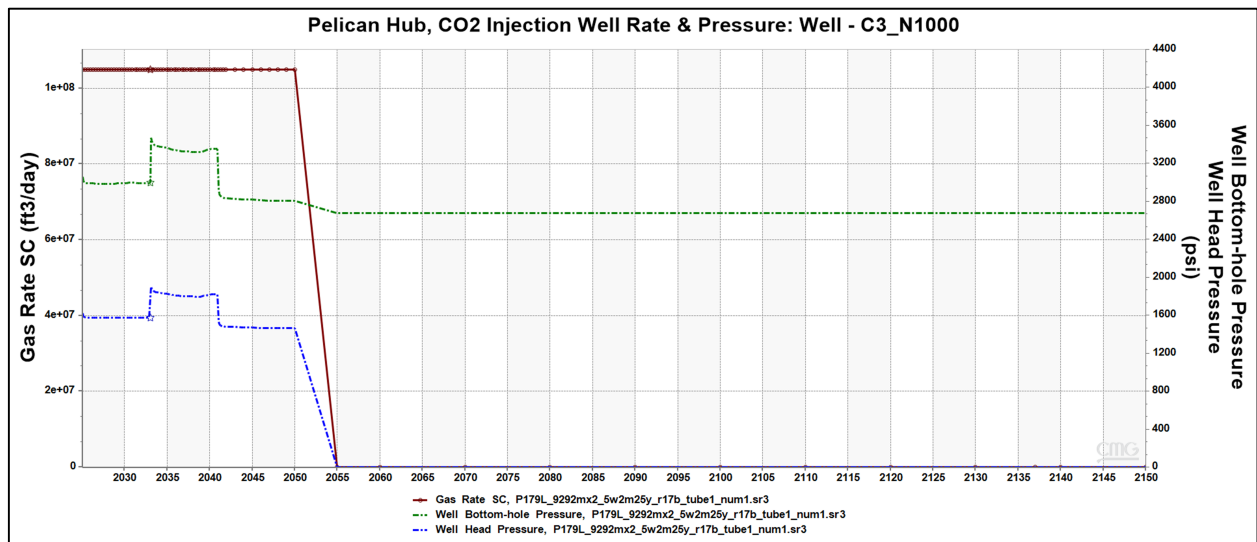


Figure AoR-21—Simulated well CO₂ injection rates and corresponding wellhead and bottomhole pressures for Pelican CCS 2.

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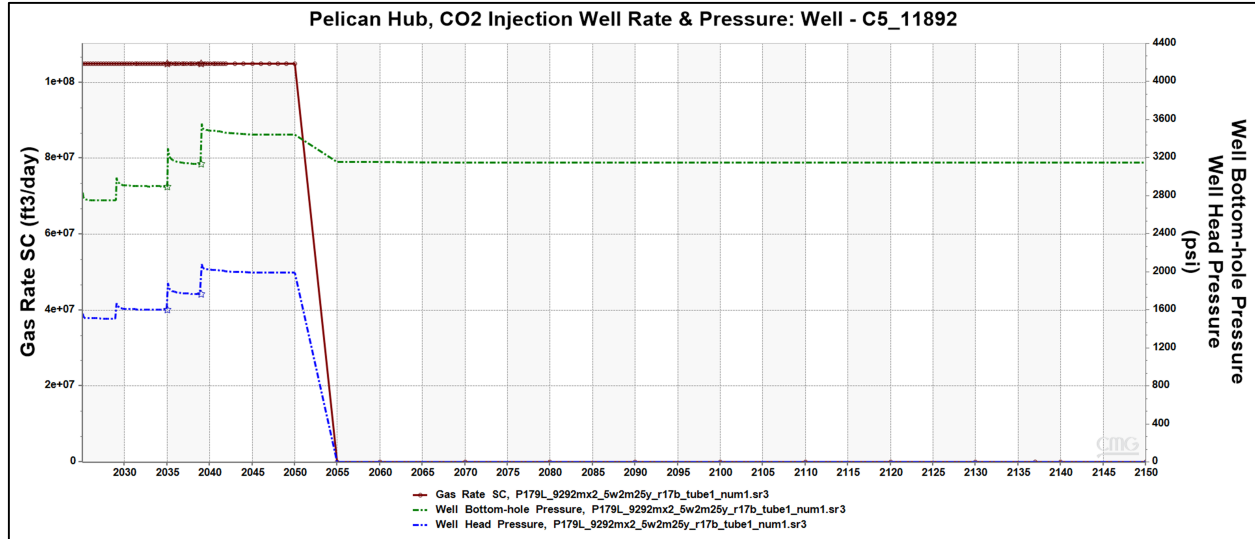


Figure AoR-22—Simulated well CO₂ injection rates and corresponding wellhead and bottomhole pressures for Pelican CCS 3.

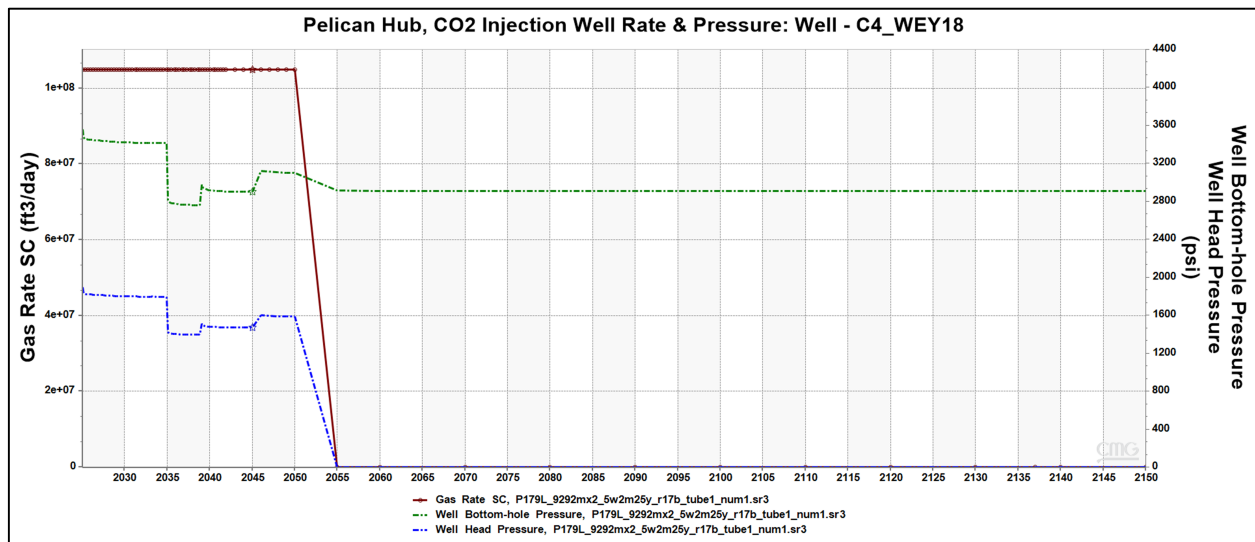


Figure AoR-23—Simulated well CO₂ injection rates and corresponding wellhead and bottomhole pressures for Pelican CCS 4.

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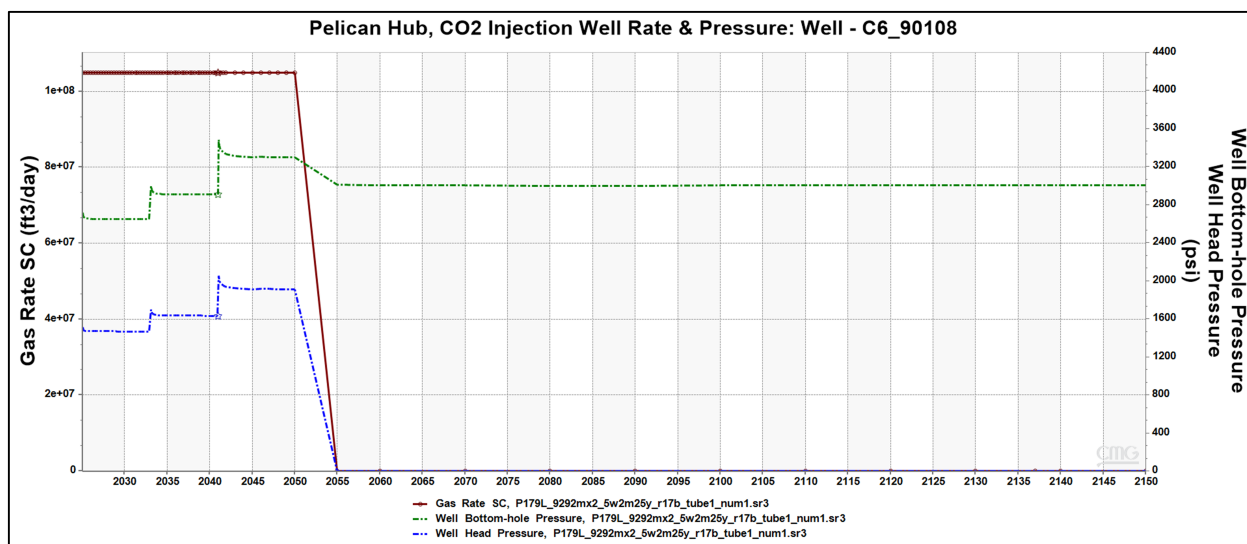


Figure AoR-24—Simulated well CO₂ injection rates and corresponding wellhead and bottomhole pressures for Pelican CCS 5.

3.2 Calibration and Validation

3.2.1 Sensitivity to Input Parameters

Any subsurface parameter estimated for use in dynamic modeling has some degree of uncertainty associated with it. Therefore, sensitivity of the results to subsurface uncertainties were explored.

The geomodel was built based on the interpretation of a diverse collection of publicly available well log data; data collected from the Pelican MLR 004 (SN 975919) well including log, whole rock, and fluid lab analyses; petrophysical interpretation of wells in the area; regional published studies; and limited in-house 2D seismic time data. Additionally, the performance of the CO₂ plume can be changed by varying the operational variables such as well completion strategy. Therefore, sensitivity of the simulation results to these uncertainties were explored.

To test the sensitivity of the dynamic modeling results, the following subsurface uncertainties were explored: storage volume, perm multiplier, porosity, Kv/Kh ratio, fault network, juxtaposition and fault transmissibility, aquifer size (aquifer volume to model volume), rock compressibility, irreducible water saturation, critical gas saturation, gas-water capillary pressure, k_{rg} @Swirr, Corey exponent for gas (N_g), Corey exponent for water (N_w), and trapped gas saturation. In addition, impacts of operational parameters such as injection completion sequence was also explored. These injection parameters were chosen as they have the potential to affect the plume migration.

Table AoR-12 summarizes the possible ranges of the subsurface uncertainties and operational parameters. Many simulation runs were made by varying these parameters one at a time and plotting the results to see their impacts. This approach to analyze uncertainty is often called the “one-variable-at-a-time (OVAT)” technique (see e.g., Ambastha, 2014). This is in contrast to uncertainty assessment using statistical design of experiment approach where many variables are

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changed together. The low and high values of the parameters were chosen to cover the expected range of uncertainty based on the current understanding of the subsurface and the field operations. For example, by varying the facies proportion curve, the variogram range and net-to-gross property assumption led to a range of storage volume, as discussed in Section 2.4.2. Likewise, mapping of the regional aquifer system resulted in the low, reference, and high-end estimates for aquifer volume to appropriately represent the range of possible outcome as elaborated in Section 2.6. The areal extent of the CO₂ plume was used as the basis to compare the different sensitivity runs.

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Table AoR-12—Uncertainty ranges of reservoir parameters simulated.

No.	Parameter	Low	Reference (Current Case)	High
1	Storage Volume	Low	Ref	High
2	Perm Multiplier	0.75	Ref (1x)	1.5x
3	Porosity	Ref – 1%	Ref	Ref + 1%
4	Kv/Kh Ratio (see table)	Low (Sst=0.4)	Ref (Sst=0.6)	High (Sst=0.9)
5	Fault Network, Juxtaposition & Fault Transmissibility	Low case TM=0.2 (TrapTester)	Ref TM=0.5 (Core observation)	High Case TM=1 Unconsolidated no proper fault plane)
6	Aquifer (Aquifer Volume:Model Volume)	Low	Ref	High
7	Rock Compressibility, psi^{-1}	Low, 1E-6	Ref (5.0E-6)	High, 10E-6
8	Irreducible Water Saturation	Sand: 0.04	Sand: 0.07	Sand: 0.12
9	Critical Gas Saturation	0.02	0.05	0.1
10	Gas-Water Capillary Pressure	No	Yes	Use Higher Pc
11	$k_{rg} @ S_{wirr}$	0.2	0.55	0.9
12	Corey Exponents For Gas (N_g)	$N_g = 2.0$	$N_g = 3.5$	$N_g = 6.0$
13	Corey Exponents For Water (N_w)	$N_w = 2.5$	$N_w = 4.5$	$N_w = 6.5$
14	Trapped Gas Saturation	Sand: 0.10	Sand: 0.15	Sand: 0.25
15	Injection Completion Sequence	Bottom Up	Optimized Ref Case	

The tornado charts of the CO₂ plume extent compared with the base case are shown in Figure AoR-. The CO₂ plume migration is most sensitive to the Corey exponent for gas (N_g), gas relative permeability at irreducible water saturation, and storage volume characteristics (facies proportion, variogram, and NTG assumptions). The plume behavior was found to be moderately sensitive to horizontal permeability, the Corey exponent for water (N_w), and trapped gas saturation. The CO₂ storage was found to be not very sensitive to the fault network and fault transmissibility, rock compressibility, and aquifer extent. The CO₂ plume migration in the saline aquifer is a complex interplay of various factors: reservoir structure, reservoir rock, and fluid properties. Therefore, the

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results of the sensitivity analysis could vary based on the parameters selected for the base case and low and high values for different parameters. With these limitations in mind, the following conclusions can be made from the dynamic model sensitivity analysis:

- 1) Relative permeability parameters to gas, the end point gas relative permeability, and the storage volume characteristics defined by facies proportion, variogram, and NTG assumptions are the most influential parameters to determine the size of the CO₂ plume.
- 2) The effect of the fault network and fault transmissibility, rock compressibility, and aquifer extent were minimal.
- 3) Horizontal permeability, the Corey exponent for water (Nw), and trapped gas saturation had a moderate effect on the final extent of the CO₂ plume.

The results of the sensitivity study suggest that reducing the uncertainty range of the relative permeability parameters and storage volume characterization will reduce uncertainty on the CO₂ plume prediction (see Figure AoR-25).

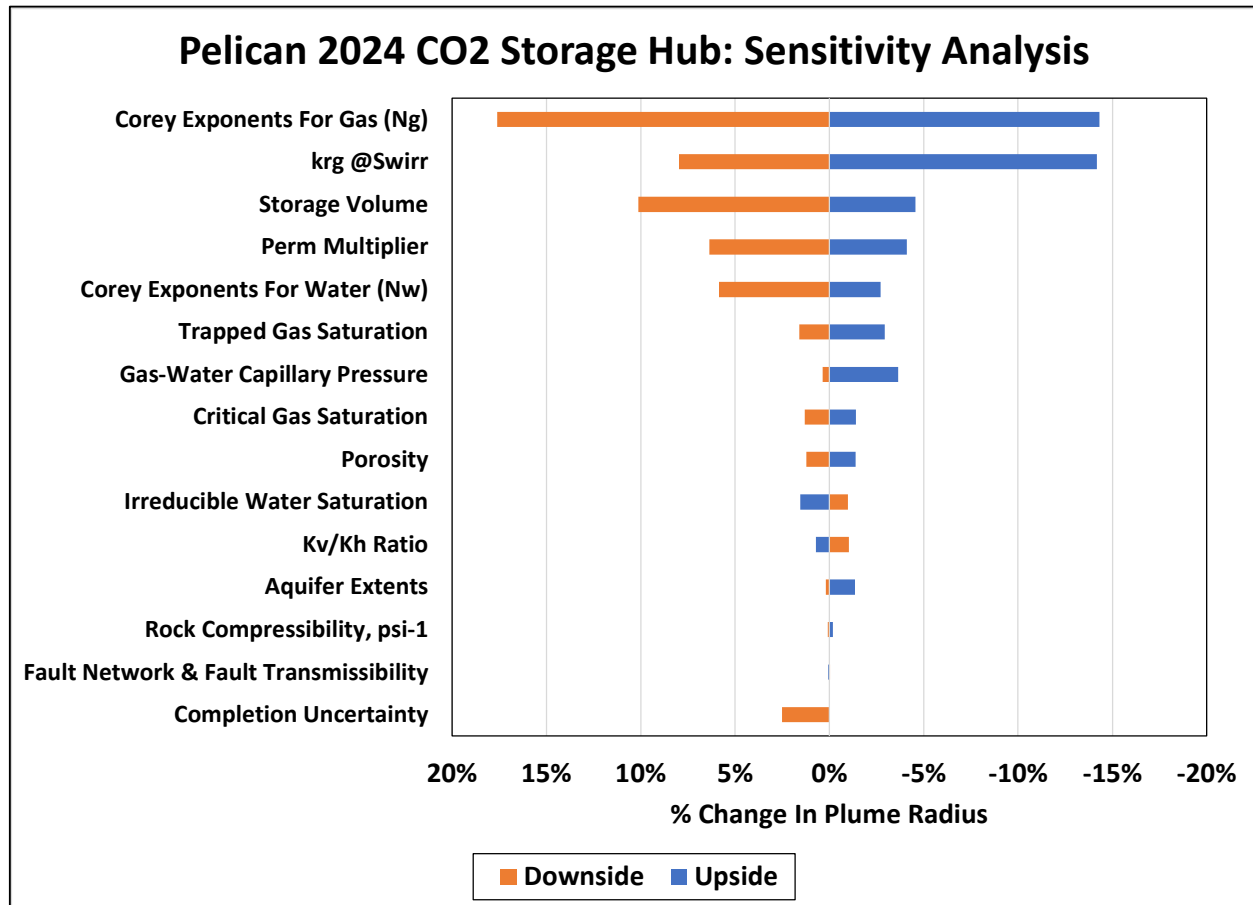


Figure AoR-25—Sensitivities of 100-year plume growth to various subsurface input parameters after 250 million MT CO₂ injection.

3.2.2 Simulation of Reactive Transport

Geochemical reactions and reactive-transport simulations are described in the Narrative (Section 2.8 Geochemical Modeling).

4.0 AoR Delineation

4.1 Threshold Pressure Calculations

To delineate the threshold pressure front, it is necessary to calculate the minimum pressure differential that can reverse flow direction between the lowermost USDW and Injection Zone, thereby causing fluid flow from the Injection Zone into the USDW formation matrix. To cause reverse flow with fluid flow to the USDW, the pore pressure increase must be high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore.

A static mud column exerts pressure. For an abandoned well to provide a pathway for fluid movement, the pressures acting on the static mud column (pressure due to injection plus original formation pressure) must be greater than the static mud column pressure.

Therefore, for upward fluid movement to begin, original formation pressure (Pf) plus the pressure due to injection (Pi) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

where:

Pf = original formation pressure (psi)

Pi = formation pressure increase due to injection (psi)

Ps = static fluid column pressure (psi)

Pg = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than the static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

The initial step in calculating the allowable buildup pressure (cone of influence) involves determining the maximum pressure buildup gradient. This gradient is derived by first calculating the mud column gradient from a 9.0 ppg wellbore mud. Note that this mud weight is less than the minimum mud weight used for artificial penetrations within the surrounding area.

In iteration, the maximum pressure buildup gradient is calculated by subtracting the original formation pressure gradient from the 9.0-lb/gal-mud column gradient.

$$0.052 \times 9.0 \text{ lb/gal} = 0.468 \text{ psi/ft (mud column gradient, modified from Barker, 1981)}$$

***0.052 is a conversion factor and has units of gal/ft-in²**

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This approach eliminates the need for determination of brine density from both USDW and Injection Zone.

Table AoR-13—Threshold pressure calculation.

Description	Value	Source
Top of Injection Zone (ft)	5,600	Completion depth
9 ppg mud to Top of Injection Zone (psig/ft)	0.468	Bump et al. (2023)
Reservoir Pressure Gradient (psi/ft)	0.445	Pelican MLR 004 (SN 975919) MDT
Column pressure (psi)	$(5600-50)*0.468 = 2,597.4$	
Initial Pressure at Top of Injection Zone (psi)	$=5600*0.445 = 2,492$	Pelican MLR 004 (SN 975919) MDT
Gel Strength Pressure (psi)	N/A	Not used in estimating the threshold pressure
ΔP_c (psi)	$2,597.4 - 2,492 = 105$	

As illustrated in Table AoR-13, the threshold pressure differential, without using the gel strength, was calculated to be 105 psi.

4.2.1 Threshold pressure front

Figure AoR-26a illustrates the propagation of the threshold pressure front at various times during the injection. The maximum threshold pressure front varied through time with injection. The movement of the pressure front was evaluated at 5, 10, 15, 20, and 25 years after injection are highlighted at this figure. Figure AoR-26b displays the maximum CO₂ plume extent after 25 years of CO₂ injection and 100 years after end of injection. The Figure AoR-26c demonstrates the maximum extent of the threshold pressure front and the CO₂ plume.

Figure AoR-27 illustrates the vertical extent of the maximum threshold pressure front, at the end of the 25-year injection period, as a cross section through the model extent with the Pelican CCS 5 location highlighted.

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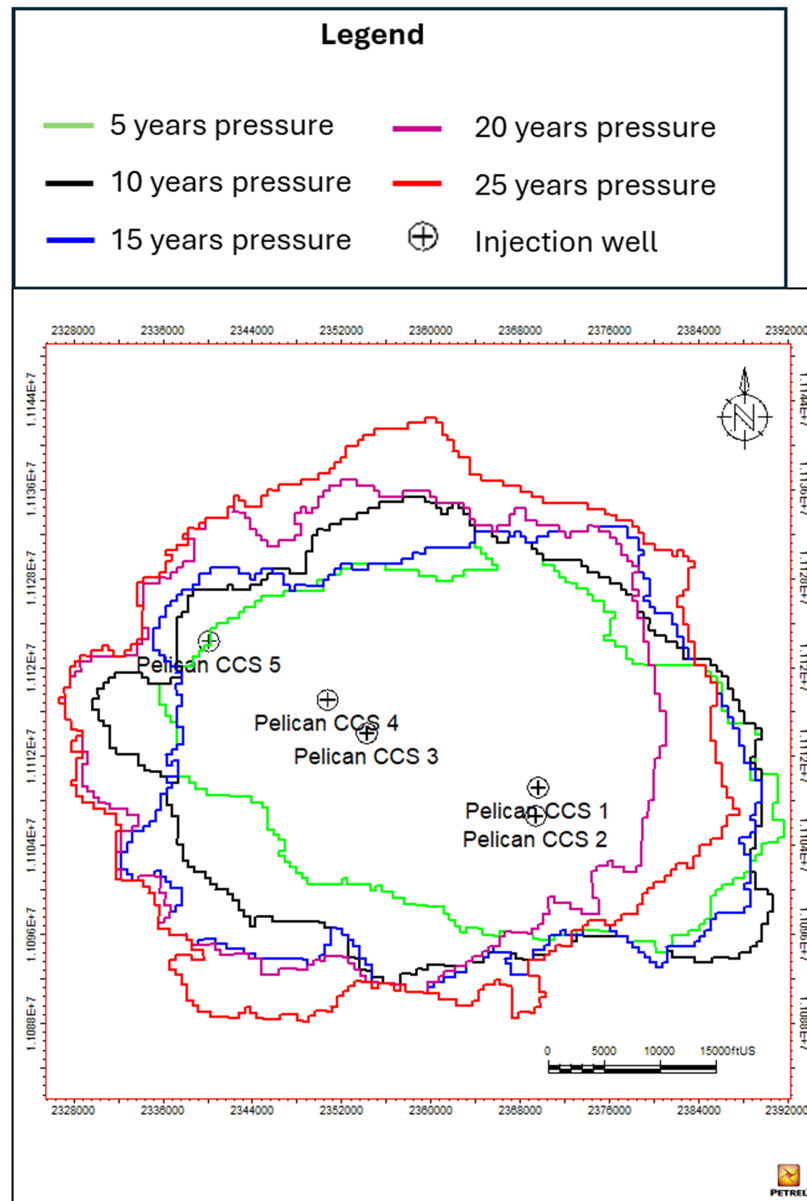


Figure AoR-26a—Areal view of the threshold pressure front (>105 psi) after 5 (green line), 10 (black), 15 (blue), 20 (dark red), and 25 (red) years of injection.

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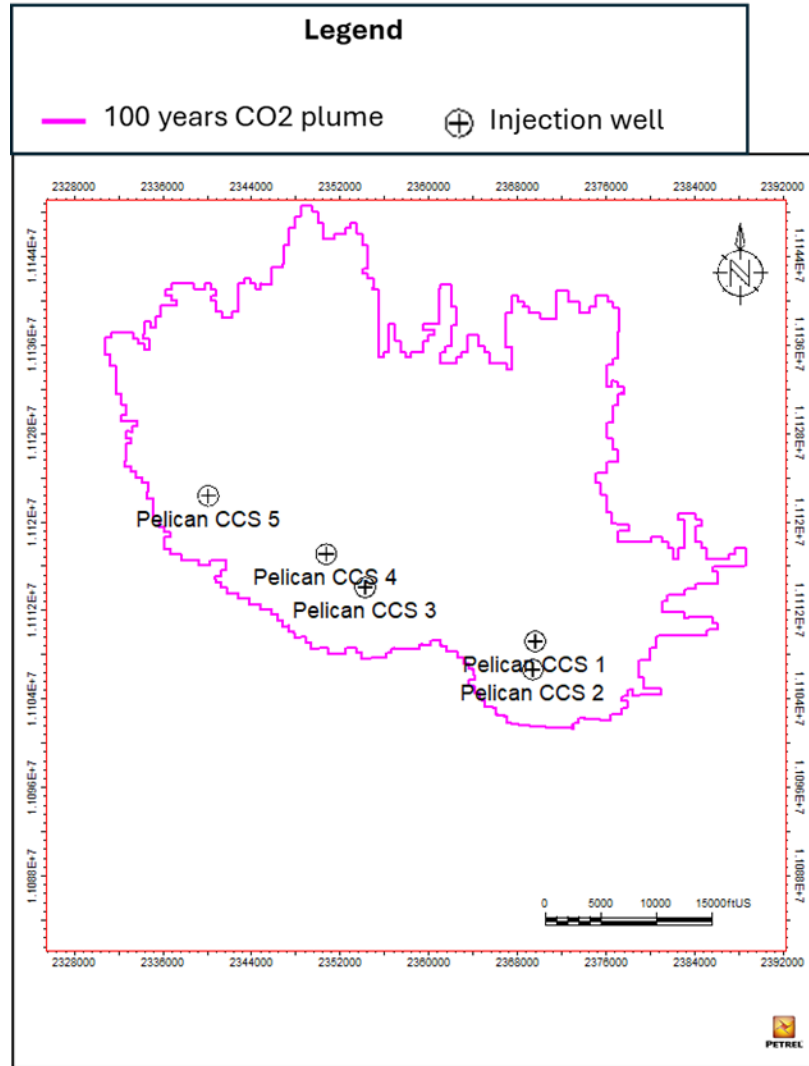


Figure AoR-26b—Areal view of the maximum CO₂ plume extent after 25 years of CO₂ injection and 100 years after end of injection.

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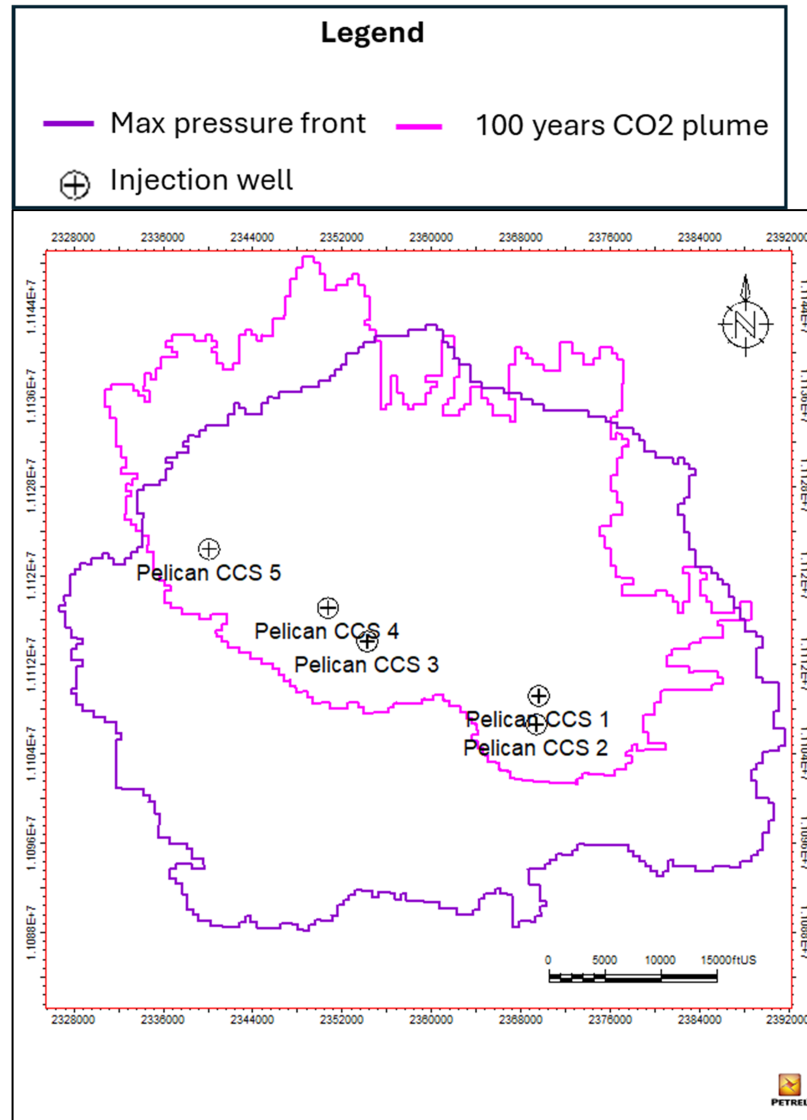


Figure AoR-26c—Areal view of the maximum threshold pressure front and the maximum CO₂ plume extent after 25 years of CO₂ injection and 100 years after end of injection.

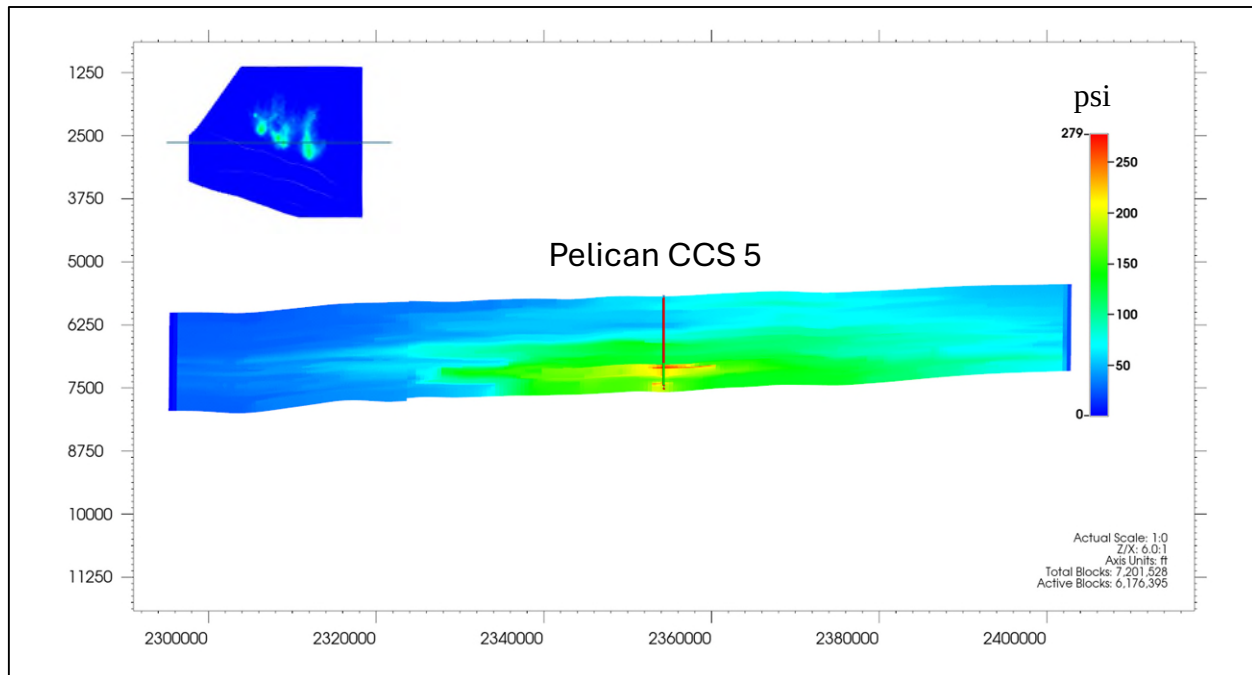


Figure AoR-27: E-W cross section through injection well Pelican CCS 5 showing the vertical extent of the pressure front at the end of injection (25 years after start of injection).

4.2 CO₂ Plume Extent

The commercially available GEM (v2024.10) reservoir simulator, with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd was used to delineate the CO₂ plume.

The injected CO₂ is concentrated near the injection wellbore, and the CO₂ concentration declines with distance away from the wellbore. A high-permeability layer in the model may result in a larger plume extent than is detectable by seismic monitoring. In addition, the grid size and numerical dispersion introduce uncertainty of ± 500 ft on the CO₂ plume edges. Therefore, Pelican Sequestration Hub, LLC, chose to implement the method described by Zhang et al. (2015), which quantifies the CO₂ plume by a percentage of the total CO₂ mass.

A value of vertically integrated mass per unit area (VIMPA) is calculated for any area of the grid containing a mass of CO₂, then the cumulative percent mass and percent area of the CO₂ plume are plotted against the VIMPA value. This plot for the Pelican injection site at 100 years after end of injection is shown in Figure AoR-28. The CO₂ plume for the Pelican injection site is the area in which 99% of the CO₂ resides, designated by VIMPA₉₉. In Figure AoR-29, 99% of the CO₂ mass at 100 years after end of injection resides in approximately 70% of the total plume area. VIMPA is a vertically integrated value, which projects the CO₂ plume onto a 2D surface. A different

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variable is required to view a cross section of the plume. Figure AoR-30 shows a north-south cross section through well Pelican CCS 1 of gas-saturation > 0.01 fraction at 50- and 100-years post-injection. The plumes at the two time periods illustrate the increase in CO₂ saturation with time and confinement of the CO₂ within the intended zones.

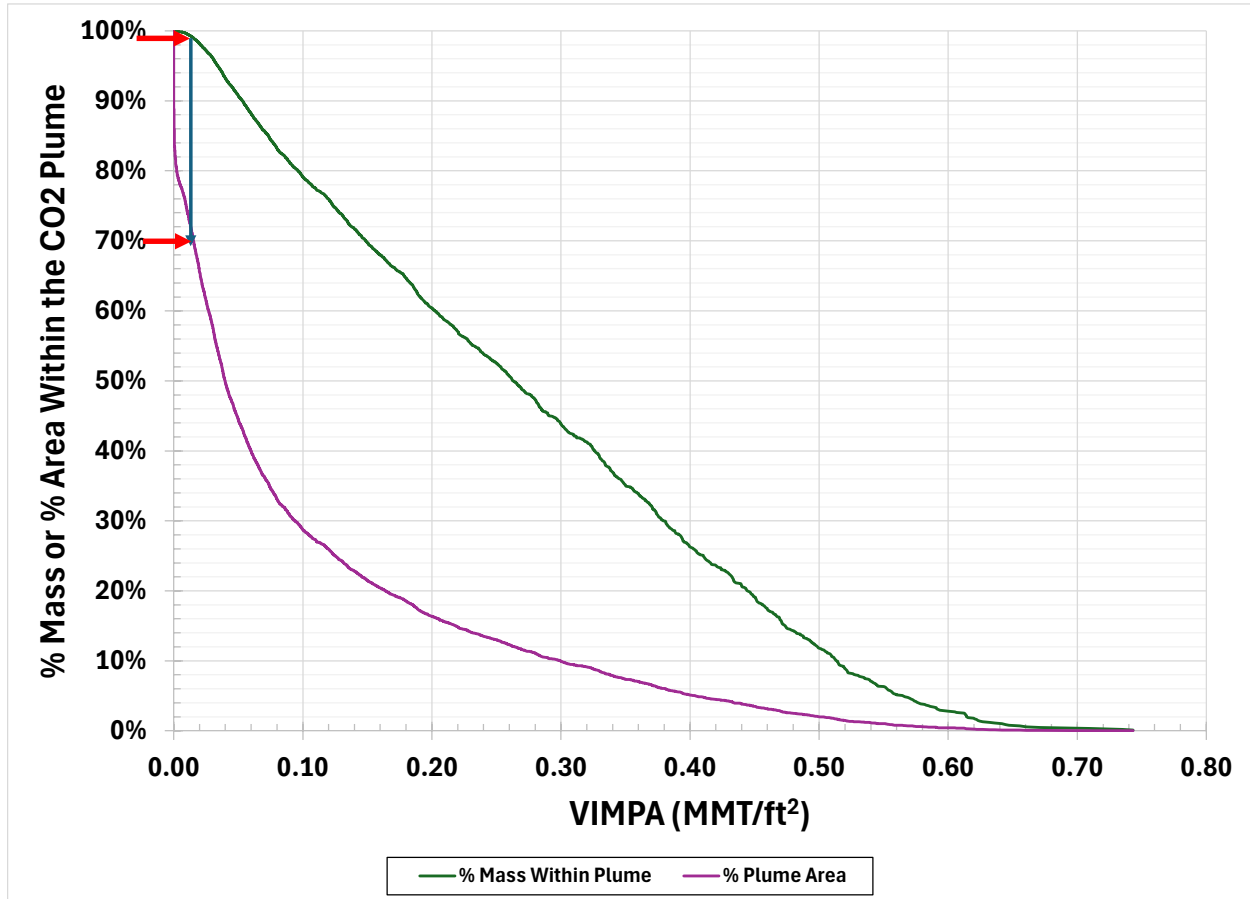


Figure AoR-28—Percent mass of CO₂ within the plume and percent of the plume area as a function of VIMPA.

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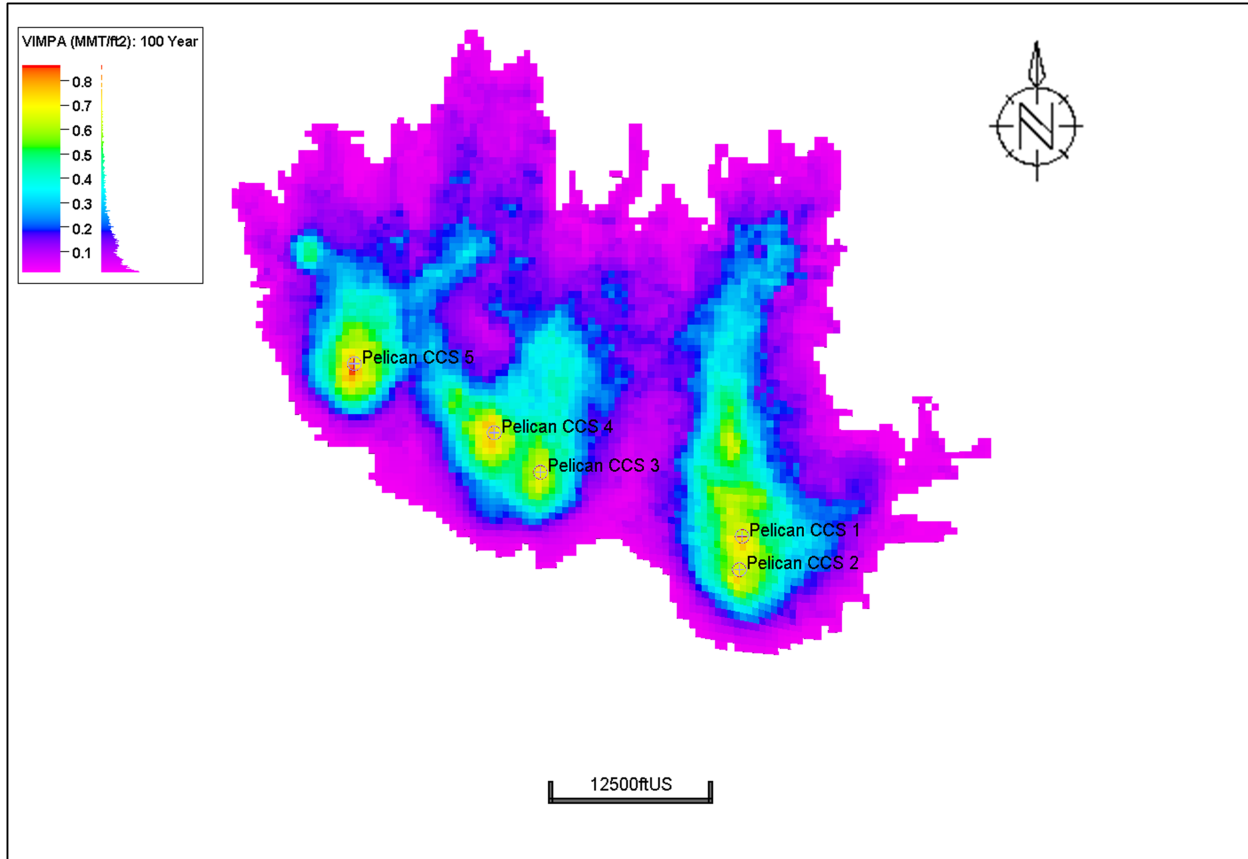


Figure AoR-29—CO₂ Plume defined by VIMPA99 (MMT/ft²) at 100 years post-injection site closure (PISC).

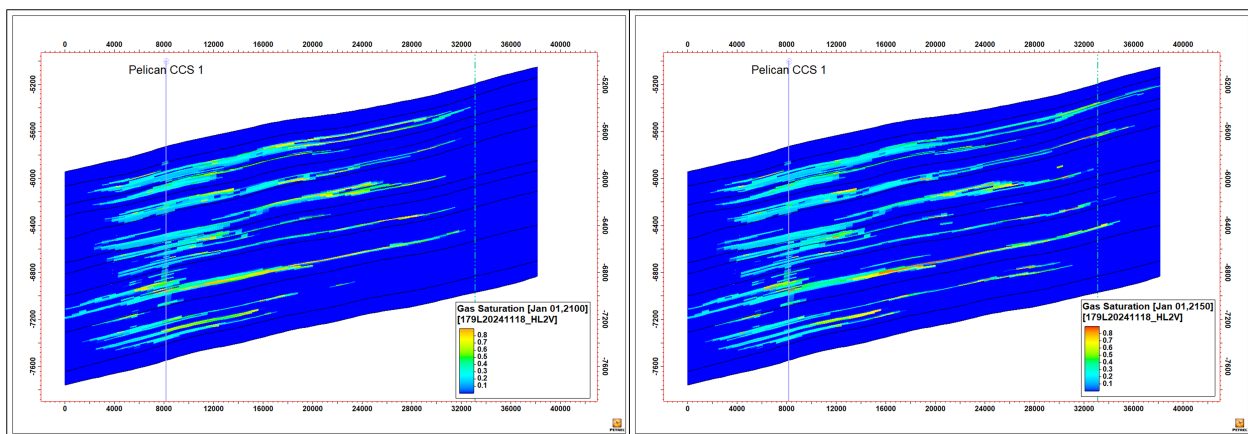


Figure AoR-30—South-north cross section through well Pelican CCS 1 showing simulated gas saturation in at 50 and 100 years PISC (simulation years 75 and 125).

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4.2.1 Combined Area of Review

The final AoR is the combination of the maximum pressure front and the maximum CO₂ plume and is shown on Figure AoR-31. The CO₂ plume is illustrated by the red line, while the pressure front is shown by the blue line.

The predicted evolution of the CO₂ plume and pressure front relative to the monitoring locations are shown in the Testing and Monitoring Plan document and PISC and Site Closure Plan document of this permit.

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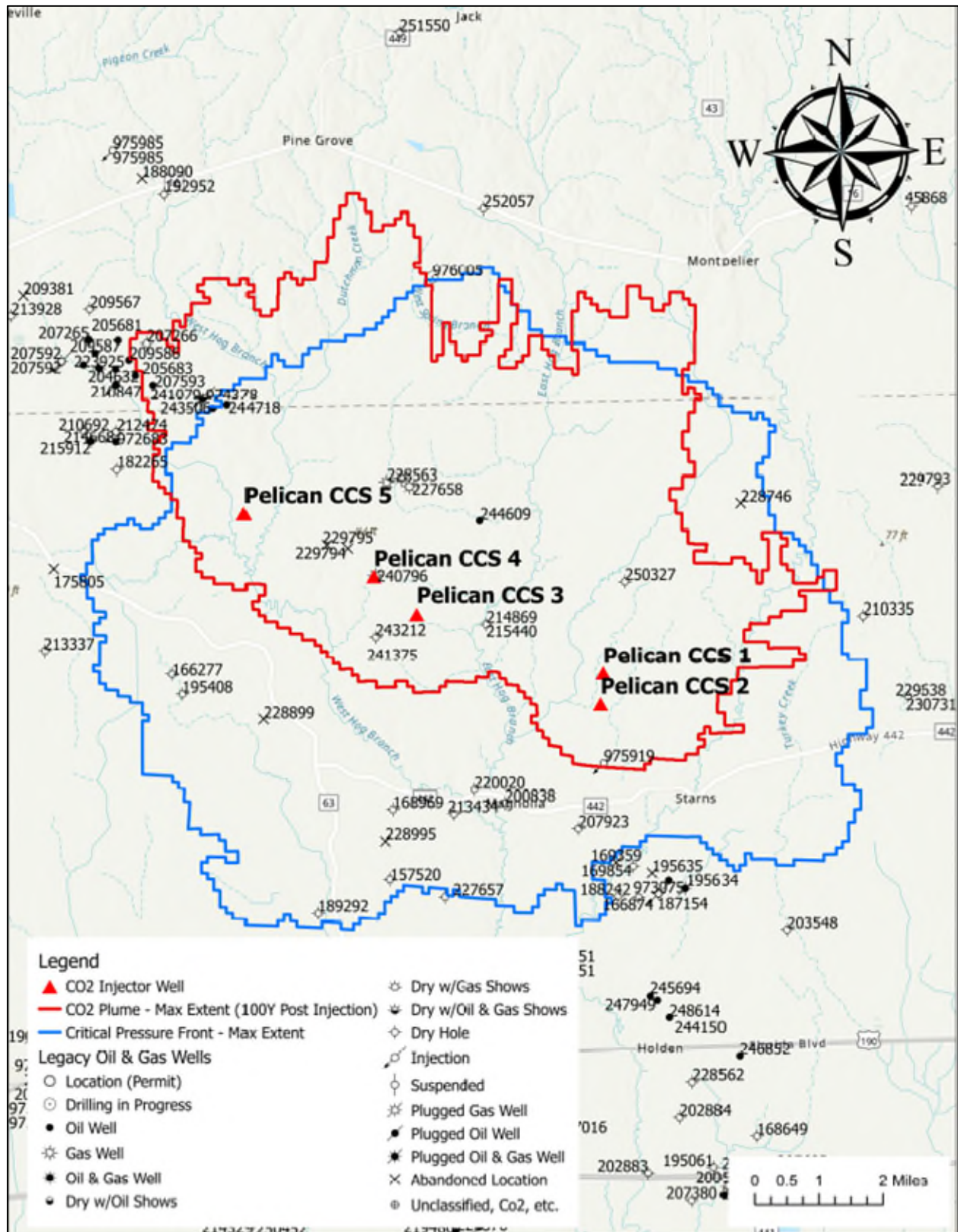
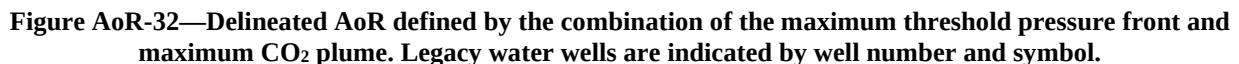


Figure AoR-31—Delineated AoR defined by the combination of the maximum threshold pressure front and maximum CO₂ plume. Legacy oil and gas wells are indicated by serial number and symbol.



4.3 Fault Leakage Assessment

The southernmost portion of the Area of Review as defined by the threshold pressure front (105 psi increase) appears to interact with some of mapped faults shown in Figure AoR-2; however the magnitude of pressure change (270 psi) predicted at the fault intersection is significantly below calculated pressure increase required to induce fault slip (2,000 psi, explained in Section 2.9). Thus, effects resulting from this distal southern pressure front extent and the fault are expected to be negligible.

A synthesis of regional and local data demonstrates that no faults are present that go through or are transmissible through the storage complex across the calculated CO₂ plume extent. See NAR Section 2.2.1.1 for a detailed discussion of fault delineation using 2D seismic data within the area—including data not available at the time of previous permit submittal.

5.0 Corrective Action

5.1 Tabulation of Wells Within the AoR

Pursuant to LAC 43:XVII.3607(C)(2)(d) and LAC 43:XVII.3607(C)(1)(a)(i) through (v), an exhaustive search using multiple methods is required to identify artificial penetrations (APs) in the Area of Review (AoR). Pelican Sequestration Hub, LLC, used the following methods when evaluating the area:

- Public records searches
 - Strategic Online Natural Resources Information System (SONRIS) online records search and interactive Geographic Information System (GIS) viewer.
 - Third-party well databases licensed by Pelican Sequestration Hub, LLC..
 - A hardcopy records search will be conducted in Louisiana Department of Conservation and Energy (C&E) central and regional offices following the magnetic survey
- Airborne magnetic survey
 - To be flown before the start of injection to verify there are no unaccounted wellbores

The final AoR delineation that includes the maximum pressure and plume extent represents approximately 95 square miles of extension and includes 26 legacy oil and gas wells and 329 water wells, according to the records obtained from C&E. The location of these wells is shown in Figure AoR-32. The area is dedicated mostly to the lumber industry, and recreational activities. Oil and gas development is present in areas outside of the AoR; however, exploration activities in the proposed AoR have not proved to be economical.

5.1.1 Water Wells Within the AoR

The 329 water wells inside the AoR are listed in Table AoR-14. The wells are mostly dedicated to domestic and irrigation activities, as well as supply for the lumber industry and the exploratory efforts of oil and gas companies. Of these wells, 304 are still active, according to C&E database.

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None of these 329 wells penetrate the Confining or Injection Zone or require any corrective action. Water well depths range from 26 ft to 2,305 ft MD and primarily target the Chicot and Evangeline equivalent aquifers (n = 326).

Table AoR-14—Water wells within the Area of Review.

Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-206	26	domestic	Active	-90.761944	30.579167
091-45	50	domestic	Active	-90.685	30.658333
063-6408Z	50	plugged and abandoned domestic	Plugged and Abandoned	-90.811389	30.601667
063-5858Z	55	domestic	Active	-90.813611	30.592222
063-5154Z	60	domestic	Active	-90.811389	30.604722
063-6146Z	60	domestic	Active	-90.808889	30.605556
063-207	60	domestic	Active	-90.803056	30.618333
063-7104Z	80	domestic	Active	-90.6525	30.624722
063-8242Z	80	domestic	Active	-90.636944	30.642222
091-6355Z	80	domestic	Active	-90.666944	30.669167
091-6341Z	80	plugged and abandoned domestic	Plugged and Abandoned	-90.748611	30.693889
063-8327Z	80	plugged and abandoned rig supply	Plugged and Abandoned	-90.740833	30.610556
063-5731Z	85	domestic	Active	-90.646389	30.598611
091-6356Z	90	domestic	Active	-90.744444	30.683333
063-5425Z	90	domestic	Active	-90.631944	30.573889
063-6610Z	90	domestic	Active	-90.773611	30.648611
063-6603Z	90	plugged and abandoned domestic	Plugged and Abandoned	-90.778056	30.649167
063-8036Z	95	domestic	Active	-90.631389	30.611111
063-5671Z	95	domestic	Active	-90.642222	30.598056
063-6600Z	95	domestic	Active	-90.778056	30.648333
063-5968Z	97	domestic	Active	-90.621944	30.595
063-7247Z	100	domestic	Active	-90.778056	30.649167
091-13400Z	100	domestic	Active	-90.763611	30.675
063-22788Z	100	domestic	Active	-90.653611	30.591944
063-22075Z	100	domestic	Active	-90.703333	30.621111
091-6125Z	100	domestic	Active	-90.775833	30.650556
063-8153Z	100	domestic	Active	-90.628889	30.608333
091-13535Z	100	domestic	Active	-90.7475	30.695
091-5644Z	100	domestic	Active	-90.7425	30.678889
091-6129Z	100	domestic	Active	-90.758333	30.651389
091-6339Z	100	domestic	Active	-90.748611	30.693889
063-8000Z	100	domestic	Active	-90.773889	30.592222

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-6811Z	100	domestic	Active	-90.795	30.632778
091-5643Z	100	plugged and abandoned domestic	Plugged and Abandoned	-90.7425	30.678889
091-5865Z	105	domestic	Active	-90.735556	30.683056
063-7827Z	107	irrigation	Active	-90.637222	30.605833
063-22469Z	108	domestic	Active	-90.651389	30.588333
091-13459Z	110	domestic	Active	-90.744444	30.682778
063-5537Z	110	domestic	Active	-90.78	30.646389
091-13380Z	110	domestic	Active	-90.7625	30.674722
063-6754Z	110	domestic	Active	-90.796111	30.634444
063-5457Z	112	domestic	Active	-90.741944	30.566389
063-7293Z	115	domestic	Active	-90.776389	30.596667
091-5653Z	117	domestic	Active	-90.781111	30.650556
091-6390Z	120	domestic	Active	-90.739444	30.680833
063-8307Z	120	domestic	Active	-90.778611	30.641667
063-22690Z	120	domestic	Active	-90.716389	30.604722
091-5575Z	120	domestic	Active	-90.732778	30.6825
063-7271Z	120	domestic	Active	-90.654167	30.574167
091-5878Z	120	domestic	Active	-90.740833	30.680556
063-22665Z	120	domestic	Active	-90.756111	30.573611
063-22657Z	120	domestic	Active	-90.704167	30.620833
091-6304Z	120	domestic	Active	-90.7525	30.6825
091-13272Z	120	domestic	Active	-90.736111	30.678889
091-5914Z	120	domestic	Active	-90.740278	30.678333
063-7274Z	120	domestic	Active	-90.713056	30.632222
063-22043Z	120	oil/gas well rig supply	Plugged and Abandoned	-90.741389	30.597778
091-5454Z	122	domestic	Active	-90.7775	30.652778
063-5978Z	123	domestic	Active	-90.668889	30.608333
091-13383Z	125	domestic	Active	-90.761944	30.673611
091-13389Z	125	domestic	Active	-90.763056	30.674167
063-6999Z	126	domestic	Active	-90.653611	30.579722
063-7828Z	130	domestic	Active	-90.636944	30.604722
063-7442Z	130	domestic	Active	-90.656667	30.574722
063-6550Z	130	domestic	Active	-90.754444	30.540556
063-5839Z	130	domestic	Active	-90.648889	30.600833
091-6001Z	130	domestic	Active	-90.745833	30.675556
091-13674Z	130	domestic	Active	-90.745833	30.675556
063-7521Z	130	plugged and abandoned domestic	Plugged and Abandoned	-90.661389	30.568611
091-13611Z	135	domestic	Active	-90.763333	30.674444

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
091-5652Z	135	domestic	Active	-90.780556	30.650556
063-7368Z	135	domestic	Active	-90.651111	30.589167
063-7672Z	135	domestic	Active	-90.690278	30.558889
063-6963Z	135	domestic	Active	-90.702222	30.645278
063-5149Z	137	domestic	Active	-90.793333	30.64
105-22869Z	138	domestic	Active	-90.623056	30.61
063-7031Z	138	domestic	Active	-90.690833	30.553333
091-5599Z	140	commercial public supply	Active	-90.734444	30.681667
063-22235Z	140	domestic	Active	-90.7025	30.585833
063-7670Z	140	domestic	Active	-90.690278	30.556111
091-13608Z	140	domestic	Active	-90.767222	30.662222
091-6222Z	140	domestic	Active	-90.743333	30.678611
063-6921Z	140	domestic	Active	-90.650278	30.5775
063-5862Z	140	domestic	Active	-90.706389	30.641111
091-13730Z	140	domestic	Active	-90.743056	30.676944
091-6388Z	140	domestic	Active	-90.764722	30.674722
063-7105Z	140	domestic	Active	-90.785556	30.598333
091-5921Z	140	domestic	Active	-90.741111	30.692778
063-22151Z	140	irrigation	Active	-90.657778	30.571944
063-7514Z	140	plugged and abandoned domestic	Plugged and Abandoned	-90.651944	30.581667
063-7644Z	140	plugged and abandoned rig supply	Plugged and Abandoned	-90.7075	30.648333
091-13371Z	142	domestic	Active	-90.756944	30.672778
063-6080Z	143	domestic	Active	-90.711667	30.576111
063-8360Z	145	domestic	Active	-90.658889	30.571667
063-22150Z	147	domestic	Active	-90.655556	30.572778
063-22509Z	150	domestic	Active	-90.638056	30.644722
063-22053Z	150	domestic	Active	-90.656389	30.572778
063-22161Z	150	domestic	Active	-90.637222	30.559722
091-13714Z	150	domestic	Active	-90.762778	30.655833
063-22762Z	150	domestic	Active	-90.6525	30.578611
063-22047Z	150	domestic	Active	-90.771944	30.648333
063-8359Z	150	domestic	Active	-90.657778	30.573056
063-22000Z	150	domestic	Active	-90.657778	30.571111
063-22001Z	150	domestic	Active	-90.658056	30.571944
063-22695Z	150	domestic	Active	-90.787778	30.627222
063-7741Z	150	domestic	Active	-90.652222	30.575556
063-22468Z	150	domestic	Active	-90.653889	30.576111

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-22474Z	150	domestic	Active	-90.655833	30.573889
091-5715Z	150	domestic	Active	-90.775278	30.650556
063-7252Z	150	domestic	Active	-90.700833	30.573056
063-6420Z	150	domestic	Active	-90.711389	30.597778
063-22614Z	150	domestic	Active	-90.650278	30.584167
063-22521Z	150	domestic	Active	-90.755	30.573333
063-8234Z	150	domestic	Active	-90.710833	30.576111
063-22946Z	150	domestic	Active	-90.652222	30.574444
063-7675Z	150	domestic	Active	-90.690278	30.558889
063-22945Z	150	domestic	Active	-90.654722	30.577222
091-5891Z	150	domestic	Active	-90.776389	30.659722
063-7287Z	150	domestic	Active	-90.656111	30.575
091-5843Z	150	domestic	Active	-90.703611	30.652222
063-7246Z	150	domestic	Active	-90.7025	30.573889
063-5853Z	150	domestic	Active	-90.656389	30.573889
063-22844Z	150	domestic	Active	-90.714444	30.573333
091-6358Z	150	domestic	Active	-90.747778	30.683611
063-7851Z	150	domestic	Active	-90.659167	30.570556
063-6828Z	150	domestic	Active	-90.650833	30.577222
063-22054Z	150	domestic	Active	-90.714167	30.5625
091-13387Z	150	domestic	Active	-90.760556	30.675
063-8004Z	150	domestic	Active	-90.661389	30.566944
091-5967Z	150	irrigation	Active	-90.776944	30.66
091-5970Z	150	irrigation	Active	-90.776667	30.660556
091-5229Z	150	oil/gas well rig supply	Active	-90.799444	30.664722
063-5631Z	150	plugged and abandoned rig supply	Plugged and Abandoned	-90.687778	30.555
063-5965Z	153	domestic	Active	-90.714167	30.563889
063-7032Z	155	domestic	Active	-90.701111	30.574722
091-13542Z	155	domestic	Active	-90.748611	30.692778
091-13543Z	155	domestic	Active	-90.747222	30.690833
063-22213Z	155	domestic	Active	-90.651389	30.576667
091-5610Z	158	domestic	Active	-90.74	30.679167
063-7021Z	160	domestic	Active	-90.654722	30.577778
063-7738Z	160	domestic	Active	-90.710833	30.576111
063-7700Z	160	domestic	Active	-90.701111	30.579444
063-8166Z	160	domestic	Active	-90.705278	30.566111
063-5467Z	160	domestic	Active	-90.649722	30.580833
063-7567Z	160	domestic	Active	-90.6625	30.578889

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-6777Z	160	domestic	Active	-90.69	30.555278
063-5468Z	160	domestic	Active	-90.701111	30.5725
091-5174Z	160	domestic	Active	-90.695833	30.664167
063-22889Z	160	domestic	Active	-90.689444	30.546667
063-22897Z	160	domestic	Active	-90.665	30.561667
063-6461Z	160	domestic	Active	-90.785556	30.597222
063-22890Z	160	domestic	Active	-90.689444	30.546667
063-7645Z	160	plugged and abandoned rig supply	Plugged and Abandoned	-90.717778	30.549444
063-6815Z	162	domestic	Active	-90.706111	30.560556
063-22758Z	165	domestic	Active	-90.660556	30.568333
063-22517Z	165	domestic	Active	-90.638333	30.643611
091-13506Z	170	domestic	Active	-90.760278	30.674444
063-5340Z	170	domestic	Active	-90.7	30.556944
063-6877Z	170	domestic	Active	-90.715556	30.563889
063-6402Z	170	domestic	Active	-90.650833	30.5975
063-22768Z	170	domestic	Active	-90.811667	30.593889
063-6845Z	170	domestic	Active	-90.710556	30.597222
063-5520Z	173	domestic	Active	-90.704722	30.536944
063-6528Z	180	domestic	Active	-90.701389	30.5825
091-13402Z	180	domestic	Active	-90.761111	30.675278
063-22389Z	180	domestic	Active	-90.755278	30.581667
063-5601Z	180	domestic	Active	-90.651389	30.563889
063-5446Z	180	domestic	Active	-90.745833	30.573611
063-7893Z	180	domestic	Active	-90.629722	30.609167
063-7515Z	180	domestic	Active	-90.754167	30.5775
063-6491Z	180	domestic	Active	-90.757222	30.578889
063-7807Z	180	domestic	Active	-90.643333	30.615
063-22939Z	180	domestic	Active	-90.7675	30.590556
063-7036Z	180	domestic	Active	-90.705833	30.538333
063-22494Z	180	domestic	Active	-90.741389	30.568889
063-8027Z	180	domestic	Active	-90.703889	30.583889
091-6166Z	180	domestic	Active	-90.780556	30.661111
063-7877Z	180	domestic	Active	-90.779444	30.638611
063-7034Z	180	domestic	Active	-90.705833	30.537778
063-7458Z	180	irrigation	Active	-90.622778	30.570278
063-6832Z	180	irrigation	Active	-90.621667	30.557778
063-22116Z	180	oil/gas well rig supply	Plugged and Abandoned	-90.713889	30.623611
091-13385Z	180	oil/gas well rig supply	Plugged and Abandoned	-90.784722	30.6525

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
091-13240Z	180	oil/gas well rig supply	Plugged and Abandoned	-90.7825	30.649722
091-6450Z	180	oil/gas well rig supply	Plugged and Abandoned	-90.785	30.651667
091-13270Z	180	oil/gas well rig supply	Plugged and Abandoned	-90.778889	30.650556
063-6860Z	180	plugged and abandoned rig supply	Plugged and Abandoned	-90.716667	30.561944
091-6405Z	180	plugged and abandoned rig supply	Plugged and Abandoned	-90.785278	30.651667
063-5739Z	183	domestic	Active	-90.708611	30.537222
063-6474Z	185	domestic	Active	-90.755278	30.56
063-22370Z	185	domestic	Active	-90.703056	30.566111
063-6636Z	188	domestic	Active	-90.756944	30.578056
063-6637Z	188	domestic	Active	-90.755833	30.576944
063-22574Z	190	domestic	Active	-90.688889	30.543056
063-6097Z	190	domestic	Active	-90.718056	30.5625
063-6109Z	190	domestic	Active	-90.651389	30.596111
063-5651Z	190	domestic	Active	-90.783889	30.595833
063-22821Z	190	domestic	Active	-90.753333	30.568611
063-7974Z	190	domestic	Active	-90.704722	30.619167
063-6814Z	190	domestic	Active	-90.768056	30.590833
063-5581Z	190	domestic	Active	-90.7075	30.556944
063-6869Z	190	domestic	Active	-90.69	30.541944
063-7890Z	195	domestic	Active	-90.753611	30.5575
063-8046Z	195	domestic	Active	-90.7175	30.55
091-6216Z	195	domestic	Active	-90.7675	30.666389
063-23063Z	195	domestic	Active	-90.713056	30.549722
063-22820Z	195	domestic	Active	-90.754444	30.571389
063-7405Z	200	commercial public supply	Active	-90.774167	30.563889
091-5432Z	200	domestic	Active	-90.666389	30.669167
063-22531Z	200	domestic	Active	-90.721111	30.559444
063-22450Z	200	domestic	Active	-90.715833	30.539722
063-5282Z	200	domestic	Active	-90.627778	30.570556
063-8304Z	200	domestic	Active	-90.788611	30.643611
063-22685Z	200	domestic	Active	-90.7075	30.543889
063-22487Z	200	domestic	Active	-90.717778	30.555
091-13460Z	200	domestic	Active	-90.758611	30.672222
063-7142Z	200	domestic	Active	-90.705278	30.634722
063-6303Z	200	domestic	Active	-90.705	30.590833
063-6469Z	200	domestic	Active	-90.760833	30.582222
063-8050Z	200	domestic	Active	-90.706111	30.618333

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-6482Z	200	domestic	Active	-90.712222	30.632778
063-124	200	domestic	Active	-90.716111	30.544722
063-22339Z	200	domestic	Active	-90.718611	30.555278
063-6121Z	200	plugged and abandoned rig supply	Plugged and Abandoned	-90.724444	30.557222
063-22005Z	203	domestic	Active	-90.720833	30.555
063-5054Z	205	commercial public supply	Active	-90.759167	30.552222
063-22238Z	205	domestic	Active	-90.720833	30.559167
063-22195Z	205	domestic	Active	-90.754167	30.614444
063-6536Z	205	domestic	Active	-90.701389	30.614722
063-7865Z	205	public supply	Active	-90.774444	30.564444
063-6818Z	208	domestic	Active	-90.754444	30.559444
063-7723Z	210	domestic	Active	-90.705278	30.548611
063-7724Z	210	domestic	Active	-90.705278	30.548333
063-6841Z	210	domestic	Active	-90.715278	30.601667
063-6842Z	210	domestic	Active	-90.763889	30.580833
063-6512Z	210	domestic	Active	-90.752222	30.5575
063-22379Z	210	domestic	Active	-90.719167	30.555
063-6743Z	210	domestic	Active	-90.621944	30.554722
063-5407Z	210	domestic	Active	-90.754722	30.553611
063-5650Z	210	domestic	Active	-90.783056	30.595833
063-8062Z	210	domestic	Active	-90.652778	30.574167
063-6557Z	210	domestic	Active	-90.693889	30.583611
063-5437Z	210	domestic	Active	-90.635556	30.569444
063-8296Z	210	irrigation	Active	-90.707222	30.541944
063-8204Z	215	domestic	Active	-90.707222	30.548056
091-13403Z	220	domestic	Active	-90.762778	30.674167
063-5984Z	220	domestic	Active	-90.649722	30.602222
063-5261Z	220	domestic	Active	-90.775	30.648889
063-22760Z	220	domestic	Active	-90.65	30.598333
063-7499Z	220	domestic	Active	-90.651389	30.583333
063-7597Z	220	domestic	Active	-90.651944	30.600833
063-5472Z	222	domestic	Active	-90.6525	30.592222
063-22148Z	225	domestic	Active	-90.754167	30.553056
063-5384Z	225	domestic	Active	-90.704167	30.535278
063-7899Z	225	domestic	Active	-90.796111	30.634167
063-5408Z	225	domestic	Active	-90.754167	30.554722
063-5348Z	228	domestic	Active	-90.629722	30.547222
063-6701Z	230	domestic	Active	-90.756389	30.614444

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-8338Z	230	domestic	Active	-90.718889	30.555
063-6800Z	230	domestic	Active	-90.651667	30.600278
063-22498Z	230	domestic	Active	-90.690556	30.551667
063-5244Z	230	plugged and abandoned rig supply	Plugged and Abandoned	-90.708611	30.559444
063-21987Z	235	domestic	Active	-90.72	30.555278
063-8116Z	240	domestic	Active	-90.698333	30.583611
063-22948Z	240	domestic	Active	-90.701389	30.585833
063-7792Z	240	domestic	Active	-90.699444	30.575278
063-8082Z	240	domestic	Active	-90.662778	30.554167
063-22546Z	240	oil/gas well rig supply	Plugged and Abandoned	-90.675278	30.608889
063-6494Z	240	plugged and abandoned domestic	Plugged and Abandoned	-90.810556	30.603889
063-6163Z	245	heat pump hole	Active	-90.815833	30.611111
091-5259Z	250	domestic	Active	-90.673889	30.673333
063-22006Z	250	domestic	Active	-90.753889	30.579444
063-7908Z	250	domestic	Active	-90.636667	30.556389
063-5090Z	250	plugged and abandoned rig supply	Plugged and Abandoned	-90.757778	30.536111
063-7978Z	255	domestic	Active	-90.7075	30.549444
063-22202Z	260	domestic	Active	-90.651944	30.58
063-7559Z	260	domestic	Active	-90.651944	30.581667
063-22294Z	260	domestic	Active	-90.651389	30.582222
063-7712Z	260	oil/gas well rig supply	Active	-90.737778	30.632778
063-8271Z	270	domestic	Active	-90.701389	30.581944
063-7879Z	270	domestic	Active	-90.637778	30.568333
063-8297Z	270	domestic	Active	-90.6525	30.581111
063-7269Z	270	domestic	Active	-90.651667	30.581389
063-8236Z	270	domestic	Active	-90.698611	30.584167
063-5389Z	275	domestic	Active	-90.659444	30.570556
063-171	275	plugged and abandoned test hole	Plugged and Abandoned	-90.657778	30.571389
063-7527Z	280	domestic	Active	-90.661389	30.568611
063-6281Z	280	domestic	Active	-90.700278	30.582778
063-6801Z	280	domestic	Active	-90.690833	30.555278
063-8090Z	280	domestic	Active	-90.662222	30.554444
063-5460Z	284	domestic	Active	-90.690556	30.553889
063-5695Z	285	domestic	Active	-90.781667	30.595556
063-5318Z	290	domestic	Active	-90.626111	30.565
063-5485Z	290	domestic	Active	-90.701667	30.578333
063-6511Z	296	domestic	Active	-90.753611	30.556389

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Water Well Number	Well Depth (ft)	Use Description	Well Status	Longitude	Latitude
063-8315Z	300	domestic	Active	-90.699167	30.585
063-5409Z	300	domestic	Active	-90.689444	30.543333
063-7485Z	310	domestic	Active	-90.651667	30.595833
063-7896Z	315	domestic	Active	-90.650278	30.577778
063-22670Z	315	domestic	Active	-90.662778	30.5575
063-7420Z	315	domestic	Active	-90.805556	30.612778
063-6927Z	317	domestic	Active	-90.698333	30.583611
063-6928Z	320	domestic	Active	-90.693889	30.543056
063-22982Z	330	domestic	Active	-90.705	30.56
063-22643Z	330	domestic	Active	-90.663889	30.555556
063-22919Z	330	domestic	Active	-90.808333	30.615556
063-5851Z	330	domestic	Active	-90.622778	30.569722
063-258	335	institution public supply	Active	-90.7875	30.599444
063-7159Z	339	domestic	Active	-90.661111	30.568056
063-6390Z	340	domestic	Active	-90.802222	30.605278
063-7150Z	340	domestic	Active	-90.805278	30.606944
063-6947Z	340	domestic	Active	-90.761944	30.579722
063-6133Z	350	domestic	Active	-90.810833	30.608333
063-22937Z	360	domestic	Active	-90.715833	30.543333
063-7189Z	360	domestic	Active	-90.793611	30.596389
063-6105Z	365	domestic	Active	-90.785556	30.597222
063-5603Z	365	domestic	Active	-90.804167	30.605278
063-6178Z	370	domestic	Active	-90.811389	30.604722
063-22586Z	370	domestic	Active	-90.661667	30.557778
063-6380Z	380	domestic	Active	-90.811389	30.601667
063-6472Z	400	domestic	Active	-90.786944	30.599167
063-7755Z	440	domestic	Active	-90.780278	30.641944
063-6180Z	465	domestic	Active	-90.779167	30.641667
063-7156Z	480	domestic	Active	-90.813056	30.595556
063-5201Z	495	domestic	Active	-90.807778	30.605278
063-6519Z	522	domestic	Active	-90.811389	30.605556
063-357	2022	municipal public supply	Active	-90.783889	30.644722
091-8	2120	industrial petroleum refining	Active	-90.663056	30.655833
063-328	2305	plugged and abandoned test hole	Plugged and Abandoned	-90.809167	30.608333

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5.1.2 Wells Penetrating the Confining Zone within the AoR

The 26 oil and gas wells within the Area of Review are listed in Table AoR-15. Well records for these wells are included in the Area of Review and Corrective Actions Plan - Appendix A. All but one (SN 974378) oil and gas wells identified in the proposed AoR were drilled through the Upper Confining Zone, with the deepest well reaching a total depth of 17,927 ft.

Table AoR 15—Oil and gas wells inside Area of Review.

Well Name	Serial No.	Status	MD (ft)	Failure Mechanism	Schedule	Inside CO2 Plume by Year	Inside Critical Pressure Front by Year	P&A Mud Weight (ppg)
VUA;WEYERHAEUSER 18 1	240796	GAS PRODUCER	5945	Plume & Pres	0	5	5	N/A
VUB;WEYERHAEUSER 19 1	243212, 241375	DRY & ABANDONED	15500	CO ₂ Plume	0	5	5	9.8
WEYERHAEUSER 4	233633	GAS PRODUCER	5515	Plume & Pres	0	10	5	N/A
WEYERHAEUSER 2	227658	GAS PRODUCER	5810	Plume & Pres	0	10	5	N/A
VUC;WEYERHAEUSER 9 1	244609	OIL PRODUCER	14836	Plume & Pres	0	20	5	N/A
WEYERHAEUSER 3	228563	GAS PRODUCER	5575	CO ₂ Plume	5	10	5	9.5
WEYERHAEUSER 14 1	250327	DRY & ABANDONED	15098	CO ₂ Plume	5	10	5	9
L TUSC RC SUA;WEYERHAEUSER 57 003-ALT	243506	OIL PRODUCER	14695	Plume & Pres	10	15	25	N/A
L TUSC RC SUB;ROBERTS 57 1	244718	OIL PRODUCER	14805	Plume & Pres	10	15	25	N/A
WEYERHAEUSER 57 1	241079	JUNKED & ABANDONED	5236	CO ₂ Plume	10	15	N/A	9
L TUSC RC SUA;WEYERHAEUSER 57 2	241282	DRY & ABANDONED	14685	CO ₂ Plume	10	15	N/A	N/A
CAVENHAM FOREST IND DIV 1	215440, 214869	DRY & ABANDONED	15100	CO ₂ Plume	15	20	5	11.1
BVDC L TUSC RA SU;D ASSOC 3	207593	OIL PRODUCER	15000	CO ₂ Plume	25	50	N/A	N/A
DENKMANN ASSOCIATES A 1	207266	DRY & ABANDONED	14950	CO ₂ Plume	50	100	N/A	9.3
BVDC L TUSC RA SU;D ASSOC 2	205683	OIL PRODUCER	14950	CO ₂ Plume	50	100	N/A	N/A
CAVENHAM FOREST IND INC 1	207923	DRY & ABANDONED	9817	None	N/A	N/A	5	9.2*
H R BANKSTON 1	200838	DRY & ABANDONED	10000	None	N/A	N/A	5	9**
WEYERHAEUSER 1	220020	DRY & ABANDONED	10004	None	N/A	N/A	5	9.3
J W SMITH ET AL 5-8 1	213434	DRY & ABANDONED	9628	None	N/A	N/A	10	9.5
CROWN ZELLERBACH 3	168969	DRY & ABANDONED	9950	None	N/A	N/A	10	9.6
CROWN ZELLERBACH 27-7 1	195408	DRY & ABANDONED	10785	None	N/A	N/A	20	9.3
CROWN ZELLERBACH 1	166277	DRY & ABANDONED	15893	None	N/A	N/A	20	9.8
CROWN ZELLERBACH 1	189292	DRY & ABANDONED	10500	None	N/A	N/A	25	9.9
CROWN ZELLERBACH 2	157520	DRY & ABANDONED	17927	None	N/A	N/A	25	13.2
*Disposed of pit fluid in well								
**Cased								

5.2 Plan for Site Access

The majority of the project wells and the wells in the remediation plan are located inside the area negotiated for injection, and a perpetual servitude was granted for the project area to allow for all project activities during pre-construction, construction, injection and operations, post-injection site care, and site closure. There are already existing roads and infrastructure in place that will be used as-is or upgraded to provide access to project well sites. For wells located outside the already leased acreage, access will be negotiated with the surface and mineral rights owners.

5.3 Corrective Action Schedule

A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching each of the wells inside the AoR, relative to the project schedule, to propose corrective actions and a timeline for these procedures. Schematics and proposed repairs for each well that penetrates the Upper Confining Zone are included in the Area of Review and Corrective Actions Plan - Appendix A.

The analysis was divided into two main categories to assess the risk and mitigations, based on the possible mechanism of failure:

- 1) **CO₂ plume corrosive effect and contamination of USDW aquifer.** The analysis focused on potential leakage paths from the Injection Zone that could endanger the USDW for those wells that are projected to be exposed to the CO₂ plume. The lack of proper isolation, cement degradation by carbonic acid, mechanical barrier failures, and micro-annulus or casing corrosion are some of the situations that increase the risk of brine/CO₂ leaks.
- 2) **Pressure front effect with brine contamination from deeper saline reservoirs to USDW aquifers and unauthorized zones.** This category includes wells that were not projected to be in contact with the CO₂ plume, but are inside the simulated pressure front. In this scenario, the wells were evaluated for proper hydraulic isolation between the Injection Zone and the USDW. The degradation or corrosion of cement, tubulars, and tools is not considered a high-risk scenario in this category.

The study was also divided into time periods from initial injection to 100 years post-injection in order to propose the schedule and approach for the corrective actions.

From the individual well analysis, 15 wells were identified that will require remedial actions to isolate the Injection Zone properly from the confining zone and USDW zones. These wells are listed in Table AoR-16 along with the main mechanism of failure and the proposed schedule. The project plans to complement this evaluation with a magnetic survey in the proposed area before starting construction operations and injection, to adjust the corrective action schedule and program. If any additional wells that penetrated the confining zone are identified (i.e., if the AoR is re-delineated to cover a larger area because of an AoR reevaluation), a revised corrective action plan and schedule will be completed as needed pursuant to LAC 43:XVII.3615(C)(1).

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Table AoR-16—Remediation schedule for wells penetrating the upper confining zone in the proposed AoR.

Serial No.	Status	MD (ft)	Failure Mechanism	Schedule	Inside CO ₂ Plume by Year	Inside Threshold pressure Front by Year
240796	GAS PRODUCER	5945	Plume & Pres	0	5	5
243212, 241375	DRY & ABANDONED	15500	CO ₂ Plume	0	5	5
233633	GAS PRODUCER	5515	Plume & Pres	0	10	5
227658	GAS PRODUCER	5810	Plume & Pres	0	10	5
244609	OIL PRODUCER	14836	Plume & Pres	0	20	5
228563	GAS PRODUCER	5575	CO ₂ Plume	5	10	5
250327	DRY & ABANDONED	15098	CO ₂ Plume	5	10	5
243506	OIL PRODUCER	14695	Plume & Pres	10	15	25
244718	OIL PRODUCER	14805	Plume & Pres	10	15	25
241079	JUNKED & ABANDONED	5236	CO ₂ Plume	10	15	N/A
241282	DRY & ABANDONED	14685	CO ₂ Plume	10	15	N/A
215440, 214869	DRY & ABANDONED	15100	CO ₂ Plume	15	20	5
207593	OIL PRODUCER	15000	CO ₂ Plume	25	50	N/A
207266	DRY & ABANDONED	14950	CO ₂ Plume	50	100	N/A
205683	OIL PRODUCER	14950	CO ₂ Plume	50	100	N/A
207923	DRY & ABANDONED	9817	None	N/A	N/A	5
200838	DRY & ABANDONED	10000	None	N/A	N/A	5
220020	DRY & ABANDONED	10004	None	N/A	N/A	5
213434	DRY & ABANDONED	9628	None	N/A	N/A	10
168969	DRY & ABANDONED	9950	None	N/A	N/A	10
195408	DRY & ABANDONED	10785	None	N/A	N/A	20
166277	DRY & ABANDONED	15893	None	N/A	N/A	20
189292	DRY & ABANDONED	10500	None	N/A	N/A	25
157520	DRY & ABANDONED	17927	None	N/A	N/A	25

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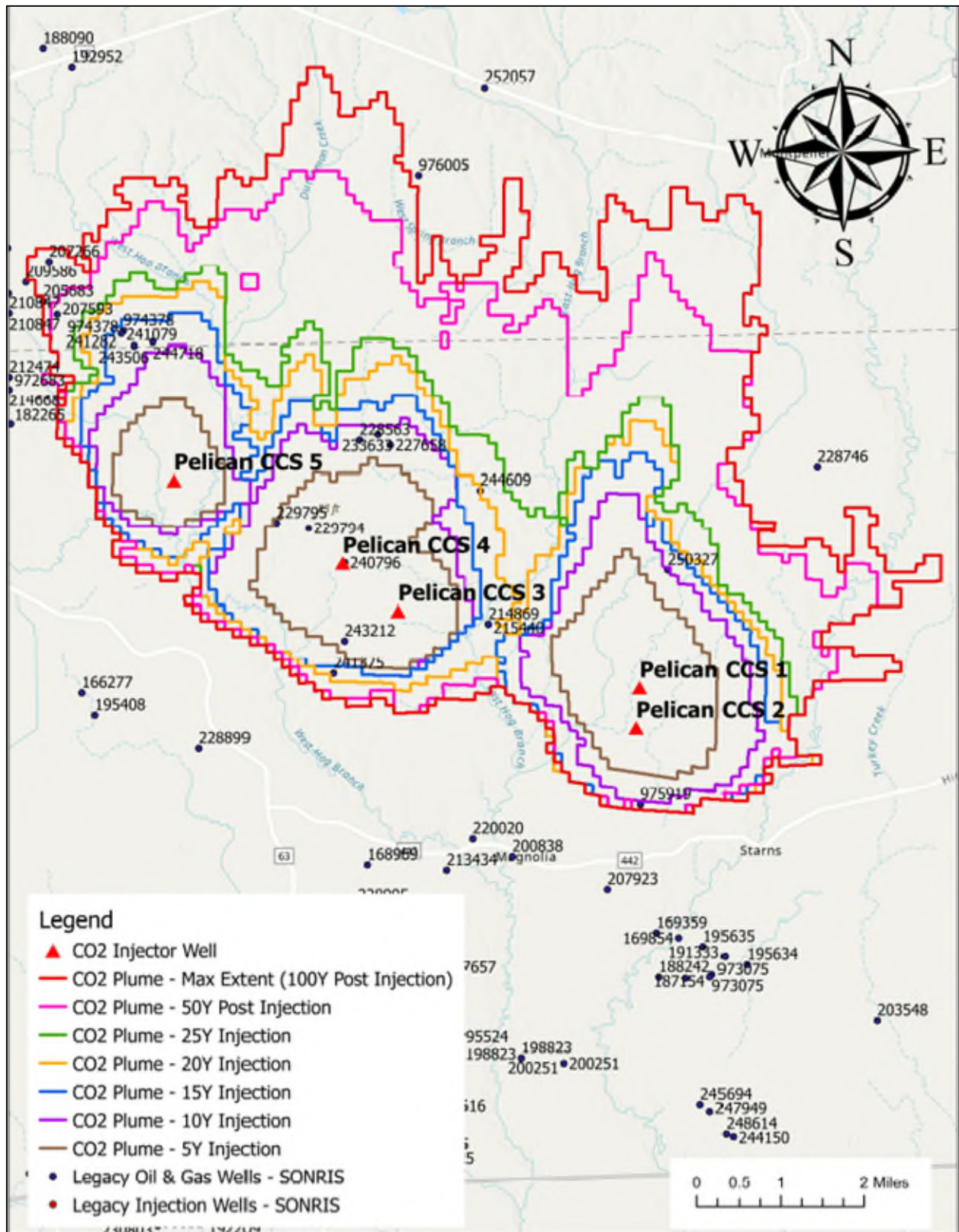
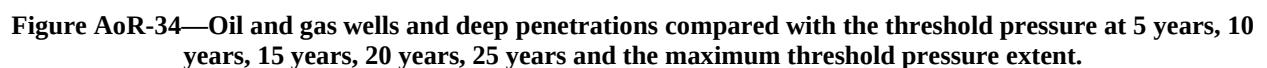


Figure AoR-33—Oil and gas wells and deep penetrations compared with CO₂ plume movement at 5 years, 10 years, 15 years, 20 years, and 25 years of injection and 50 years and 100 years after injection.



6.0 Reevaluation Schedule and Criteria

6.1 AoR Reevaluation Cycle

Pelican Sequestration Hub, LLC, will reevaluate the AoR every five years during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by Pelican Sequestration Hub, LLC, during the injection and post-injection phases.

Activities to be performed during reevaluation include reviewing and analyzing available monitoring and operational data and comparing it to the dynamic simulation forecast to assess whether the predicted CO₂ plume migration is consistent with the actual data. This includes data from the CO₂ injector wells, monitoring wells, geophysical surveys, and other sources. The monitoring activities to be conducted are described in the Testing and Monitoring (TM) Plan and the Post-Injection Site Care and Closure Plan (PISC).

Specific steps of this review and analysis include:

- Reviewing collected data on the position of the CO₂ plume and pressure front. This data will be collected from the CO₂ injector wells, monitoring wells, and near-surface monitoring systems as well as geophysical surveys as described in the testing and monitoring plan.
- Reviewing water chemistry monitoring data taken in the USDW monitoring wells and verifying that there is no evidence of CO₂ or brines that represent an endangerment to any USDWs.
- Reviewing operating data (e.g., injection rates and pressures) and verifying consistency with the inputs used in the most recent modeling effort. History-match the numerical simulation model with operational data for well performance.
- Reviewing any geologic data acquired since the last modeling effort (e.g., additional site characterization performed and updates of petrophysical properties from core analysis). Identify whether any new data is materially different from the modeling inputs and assumptions.
- Comparing the results of computational modeling used for AoR delineation to the monitoring data collected. Monitoring data will be used to history-match the computational model and validate that the model provides an accurate representation of the storage site and can be used as a proxy to determine the plume's properties and size. The degree of accuracy is demonstrated by comparing monitoring data with the model's predicted properties (e.g., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately.

If the collected data is consistent with model inputs and/or if the model forecast has not materially changed after the incorporation of such data, no update to the AoR will be needed. In this case, a report will be prepared to demonstrate that, based on the monitoring and operating data, no

reevaluation of the AoR is needed. This report will include the data and results demonstrating that no changes are necessary.

If material changes in site conditions or operating parameters have occurred or if data indicates that the actual plume or pressure front may extend beyond the modeled plume and pressure front, the AoR will be re-delineated. Steps to re-delineate the AoR include:

- Revising the site conceptual model based on the new site characterization, operational, or monitoring data.
- Calibrating and history-matching the model in order to minimize the differences between monitoring data and model simulations.
- Performing the AoR delineation method as described in the AoR Delineation section of this AoR and Corrective Action Plan.
- Reviewing wells in any newly identified areas of the AoR and applying corrective action to deficient wells if needed. Specific steps include:
 - Identifying any new wells within the AoR. Evaluate the status and records for wells that were not evaluated previously and provide description of each well including well type, construction, date drilled, location, depth, and record of plugging and/or completion.
 - Determining which wells in the newly delineated AoR are constructed or plugged/abandoned in a manner that could be a risk for endangering USDWs.
 - Performing or scheduling corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, using materials compatible with CO₂.
- Preparing a report documenting the AoR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to C&E within one year of the reevaluation and will include maps that highlight similarities and differences with previous AoR delineations.
- Updating the AoR and Corrective Action Plan to reflect the revised AoR along with other related project plans, as needed.

6.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

Unscheduled AoR reevaluations will be based on quantitative and material changes of the monitoring and operative parameters in CO₂ injectors, monitoring wells, seismometer networks, and geophysical surveys that could indicate that the actual plume and pressure front may extend

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beyond the area modeled or outside the proposed storage complex. These changes might include, but not be limited to the following:

- **Pressure:** Changes in pressure that are unexpected in timing or magnitude from those predicted by the model.
- **RST Saturation:** Increases in CO₂ saturation in monitoring wells that indicate a earlier breakthrough of CO₂.
- **Deep Groundwater Constituent Concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of CO₂ or brine into or above the confining zone.
- **Exceeding Fracture Pressure Conditions:** Pressure in injection wells exceeding 90% of the geologic formation fracture pressure.
- **Compromise in Injection Well Mechanical Integrity:** A significant change in annular pressure for the injection well or abnormal reading of temperature in the fiber optic cable that indicates a loss of mechanical integrity or a failed mechanical integrity test (MIT) in an injector or monitoring wells.
- **Induced Seismicity Monitoring:** Seismic monitoring data that indicates reactivation of a fault or structures due to pressurization of the reservoir because of the CO₂ injection. The project will review the monitoring data to discard naturally occurring events not related to the injection.

Pelican Sequestration Hub, LLC, will discuss any such events with the Commissioner to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, Pelican Sequestration Hub, LLC, will perform the steps described in 6.1 AoR Re-evaluation Cycle.