SECTION 1 – SITE CHARACTERIZATION

TABLE OF CONTENTS

Figures

Tables

1.1 Overview

This site characterization for the Lapis Energy (LA development), LP (Lapis) Libra CO_2 Storage Solutions Project(Libra) was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3607.C.2.m** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.82(a)(3)**]. This section describes the regional and site geology for the proposed locations of three Class VI CO_2 injection wells, Simoneaux CCS Injector Wells No. 001, No. 002 , and No. 003. The site characterization incorporates analysis from several data types from public, proprietary, and licensed data sets, including well logs, 3D seismic, academic and professional publications, and existing core-sample analyses.

1.2 Regional Geology

The Libra project site is located in southeastern Louisiana, in the Gulf of Mexico (GOM) sedimentary basin, as shown in Figure 1-1. The GOM originated as a small ocean basin created by the rift of Pangaea, which resulted in crustal extension and seafloor spreading during the Middle Jurassic through Early Cretaceous (Galloway, Whiteaker, & Ganey-Curry, 2011). By the end of the Mesozoic, mixed carbonate and clastic sedimentation had constructed a northern basin margin characterized by a broad coastal plain and shelf fronted by a well-defined shelf edge and continental slope. Beginning in the late Paleocene, large volumes of terrigenous clastic sediment began to enter the basin from continental North America, constructing large fluvial-deltaic systems along an extensive, prograding continental margin (Galloway W. , 2008). Alternating sequences of sediment starvation during eustatic sea-level rise and rapid sedimentation from fluvial-deltaic continental sources formed the depositional framework responsible for the evolution of one of the world's most studied geologic basins.

Seafloor spreading during the Middle Jurassic was asymmetric, creating a broad area of attenuated transitional continental crust beneath the northern basin. Initially, widespread, thick evaporitic deposits of anhydrite and salt beds, collectively known as the Louann Salt, formed a blanket over the late Triassic–early Jurassic sediments, the earliest recorded deposition in the basin (Galloway W. , 2008). As high rates of terrigenous sediment were transported into the basin, the weight of this sedimentary loading led to the mobilization of the Louann Salt via buoyant forces. Salt movement compounded with the extensional environment of the basin makes normal faults, often referred to as "growth" faults, a very common structural feature in the GOM basin. The earliest growth fault activity in the Gulf Coast is generally regarded as Eocene (Wilcox), with active fault movement still taking place today (Durham Jr., 1974).

Figure 1-2 shows the location of the regional cross section line presented in Figure 1-3. A panel of basin-scale, dip-oriented (north-south) cross sections over the projected area of the proposed CO_2 storage site is shown in Figure 1-3, illustrating the evolution of salt canopies and fault complexes of the GOM continental margin. Note the massive scale of deposition that took place in the Oligocene through the Miocene and the reaction of the salt to this sediment loading.

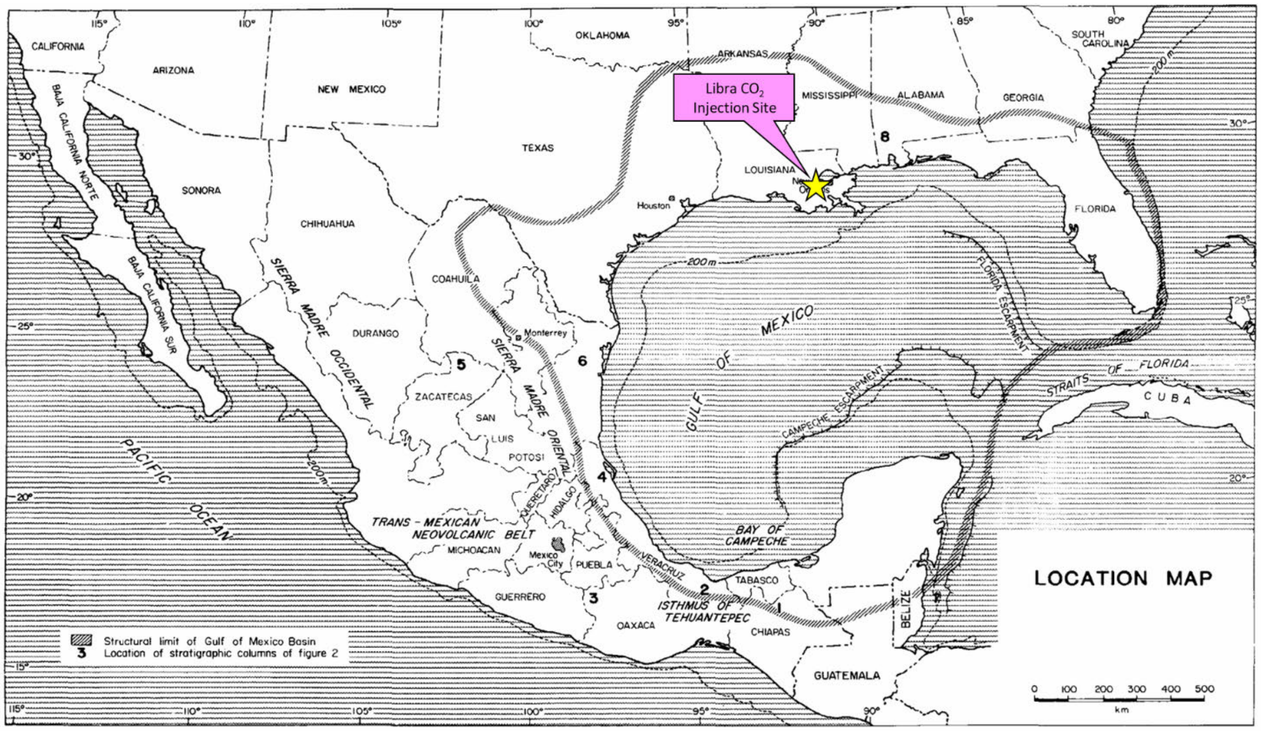

Figure 1-1 – Gulf of Mexico map showing the location of the proposed Libra CO_2 injection site (modified from Salvador, 1987).

Figure 1-2 – Regional map of the Gulf of Mexico basin showing the location of the cross section line in Figure 1-3.

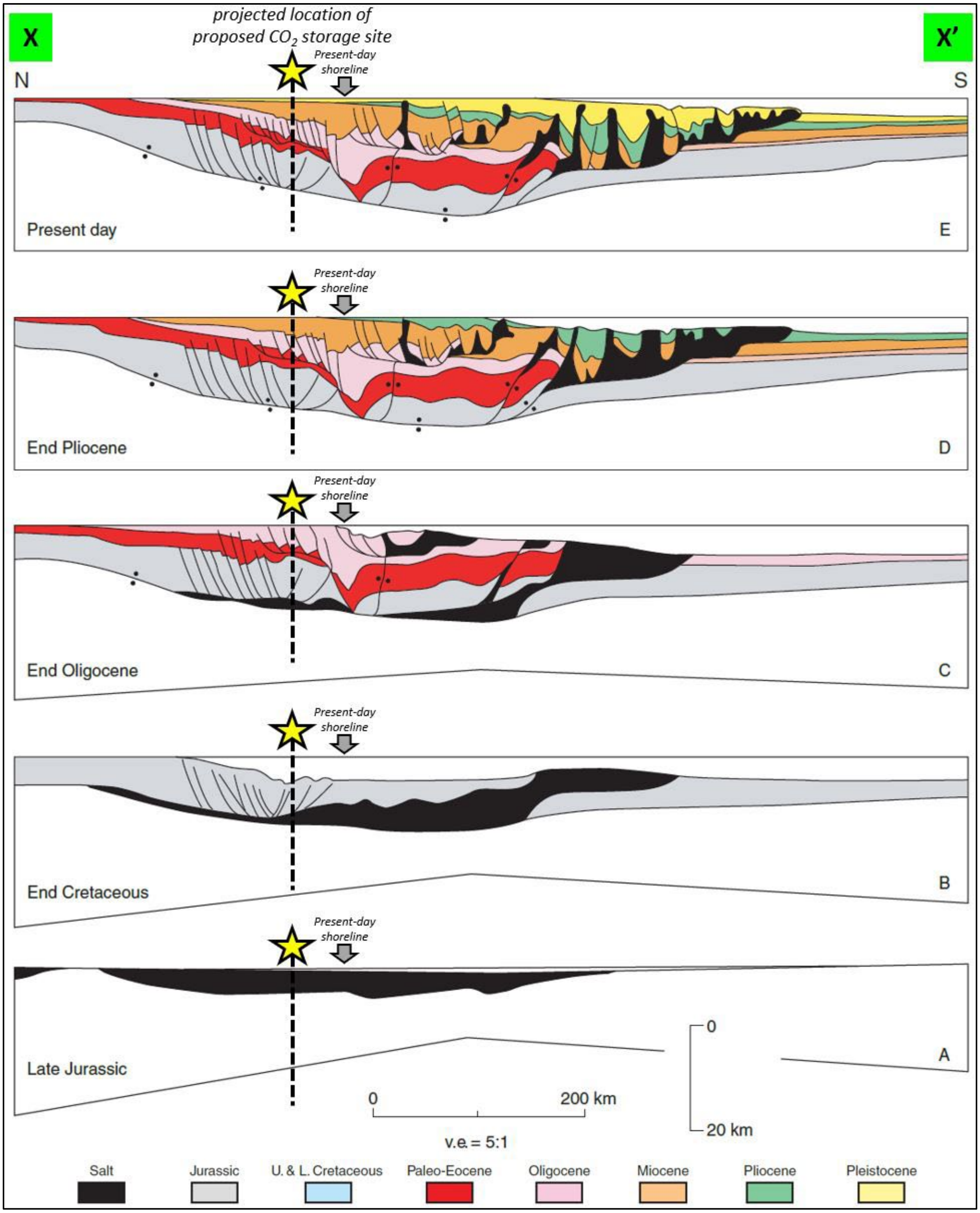

Figure 1-3 – Schematic cross section panel showing the evolution of the Gulf of Mexico basin from the late Jurassic to present day. The approximate, projected location of the proposed CO_2 storage site and the present day shoreline are annotated on the image (modified from Galloway, 2008).

This study focuses on the Miocene geologic section, as it is the proposed CO_2 injection interval. The proposed injection site is in the eastern part of St. Charles Parish, Louisiana, approximately 17 miles (mi) southwest of New Orleans. To fully appreciate the local site geology and how it fits into the greater GOM basin, a basic understanding of the regional structural setting is required. There are four widely recognized structural provinces in the Cenozoic of the northern GOM basin as shown in Figure 1-4 (modified from Peel, Travis, and Hossack, 1995). These structural provinces have different stress regimes and therefore influenced deposition and faulting differently. The proposed Libra CO_2 storage site is represented by the yellow star on Figure 1-4, located at the northern extents of the Eastern Province.

The Eastern Province is characterized by a combination of the following features: (1) a major linked system of extension and contraction—principally of middle-late Miocene-age extension probably located under the present-day shelf, to contraction in the Mississippi Fan fold belt; (2) a large salt canopy on the present-day middle slope, formed in middle-late Miocene; and (3) a largely evacuated salt canopy located under the present-day shelf emplaced in the Paleogene (Peel, Travis, & Hossack, 1995).

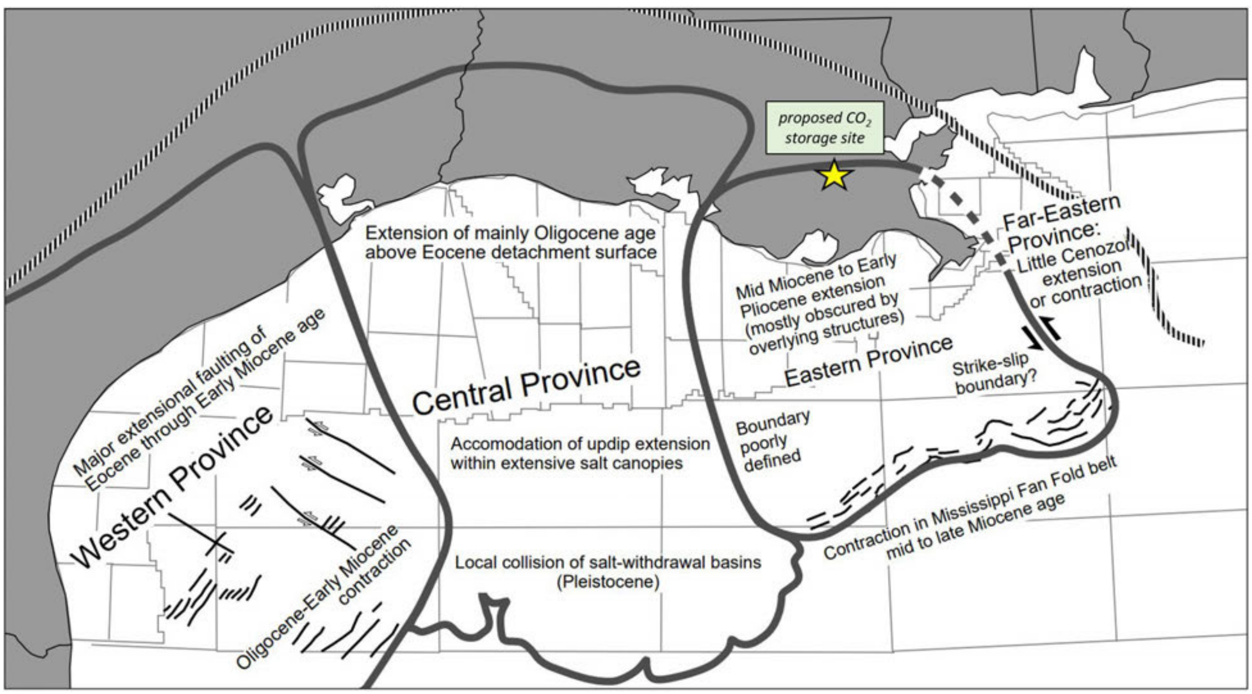

Figure 1-4 – Division of the northern Gulf of Mexico margin into Cenozoic structural provinces, with major characteristics of each province labeled on the map. The approximate location of the proposed CO_2 storage site is represented by the yellow star (modified from Peel, Travis, and Hossack, 1995).

The Cenozoic section in the Eastern Province is thicker than in the Far-Eastern Province and is especially thick in the salt withdrawal basins under the present-day shelf, where the proposed CO_2 storage site is located. Extreme sediment loading, primarily from the Mississippi River system, resulted in large episodes of salt withdrawal, leaving evacuated mini-basins for younger Miocene sediments to infill, hence the thicker accumulations in this province.

Several salt domes, both deep-seated and piercement style, occur in the study area and surrounding regional Miocene trend, as shown in Figure 1-5. Salt domes proximal to the study area include Bayou Couba (a piercement dome with the top of the salt recorded at -6,160 feet (ft) true vertical depth subsea (TVDSS)) to the east-southeast, Bayou Des Allemands (piercement dome with top of salt recorded from -7,560 ft to -10,295 ft TVDSS) to the south, and Paradis (deep-seated dome at -13,500 ft TVDSS) to the west-northwest. There is also a trend of regional faults predominantly striking east-west, that are both northerly and southerly dipping due to the extensional tectonic environment in an embayment of salt domes and associated withdrawal basins. A pair of east-west, down-to-the-south arcuate growth faults to the north of the study area set up Boutte Field. Oil is predominantly trapped on the downthrown sides of the two faults in the older middle- and lower-Miocene sands of *Cibicides opima* (9,700 ft TVD) to *Robulus L* (12,600 ft TVD), which sit below the *Cristellaria I* shale—the proposed lower confining zone.

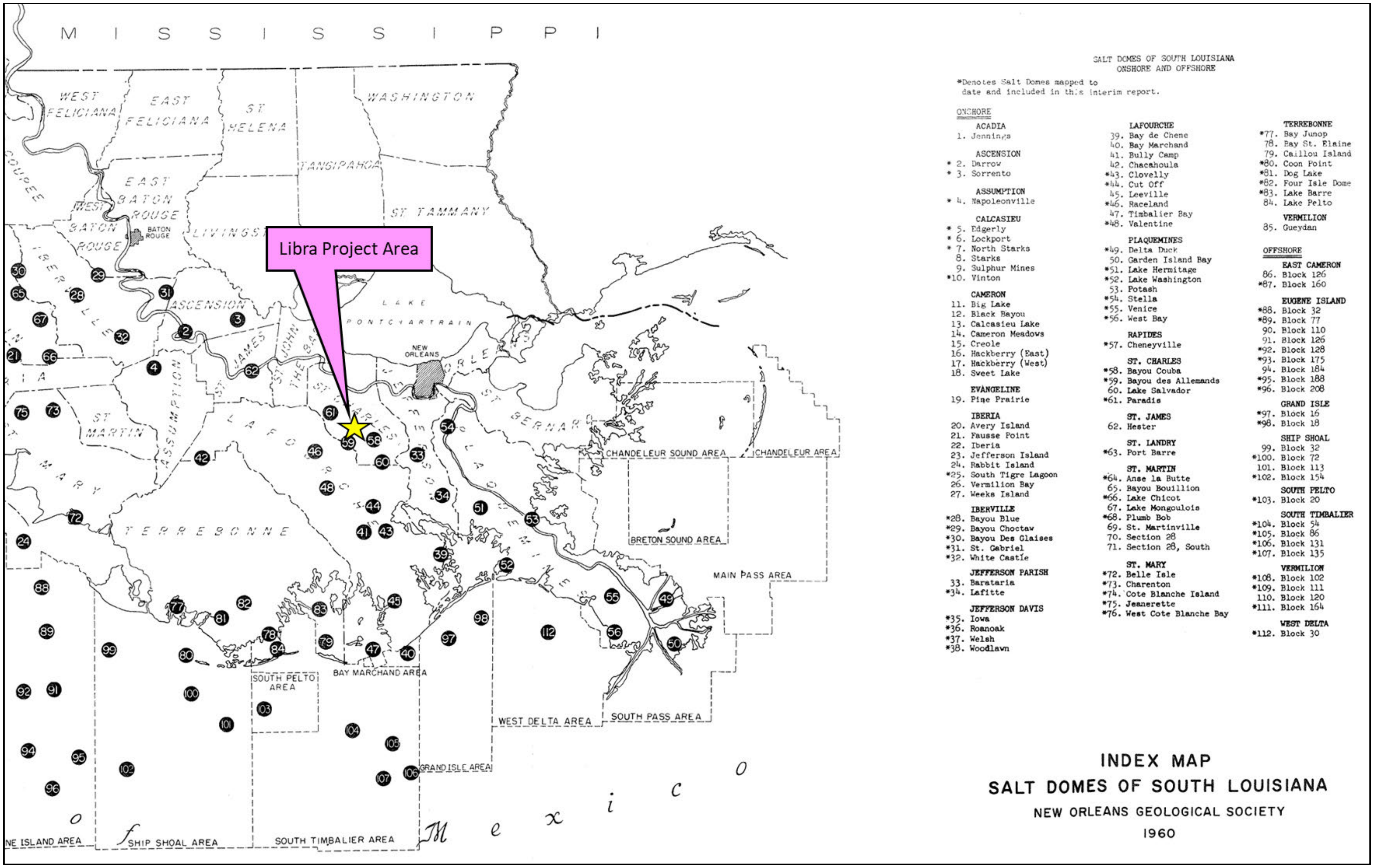

Figure 1-5 – Regional map of southeast Louisiana showing the locations of identified salt domes. The yellow star indicates the Libra project area (modified from New Orleans Geological Society, 1960).

1.2.1 Major Stratigraphic Units

Sediment supply rate to the GOM has varied extensively through Cenozoic time, which is a significant, independent variable in the development of stratigraphic sequences within the GOM basin (Galloway, 1989). Sediment supply reflects the interplay of five variables: (1) areal extent of river drainage basins, (2) source area relief, (3) climate of the source areas and tributary systems, (4) lithology of the sediment sources, and (5) sediment storage within the drainage basin (Galloway, Whiteaker, & Ganey-Curry, 2011). These five variables drive the differences in depositional environments, basin capacity, and accumulation of sediment for the major stratigraphic units described herein.

Miocene depositional episodes are generally fluvio-deltaic systems interrupted by extensive, fine-grained sealing units during marine transgressions. This geologic section is predominately terrigenous, clastic sediments deposited during periods of rapid subsidence and deposition. The Miocene is subdivided into three stratigraphic units: the Lower, Middle, and Upper Miocene.

The targeted formations for this application are Upper and Middle Miocene-age sediments, deposited between 5½ million years ago (m.y.), and 15 m.y., respectively. Figure 1-6 depicts the stratigraphic column of the GOM basin Tertiary depositional episodes, and a detailed Miocene coastal onlap curve with associated key biochronozone markers (modified from Meckel and Trevino, 2014). The transgressive and regressive environments represented by these coastal onlap curves are responsible for the deposition of the regional shales encasing the proposed injection sands. Stratigraphic intervals directly relevant to this project are highlighted according to their associated function during proposed injection operations.

The pressure gradient in the study area starts building at approximately 10,500 ft TVD, with a sharp transition to overpressure at 11,800 ft to 12,000 ft TVD based on mud weight analysis and intermediate casing depths observed in offset well control. The deepest of the three Libra project injection wells, Simoneaux CCS Injector Well No. 001, is proposed to reach total depth (TD) at 9,975 ft before the build-in pressure. With the lack of quality, thick injectable sands in a shale-rich interval where overpressure occurs, deeper formations were precluded from this study.

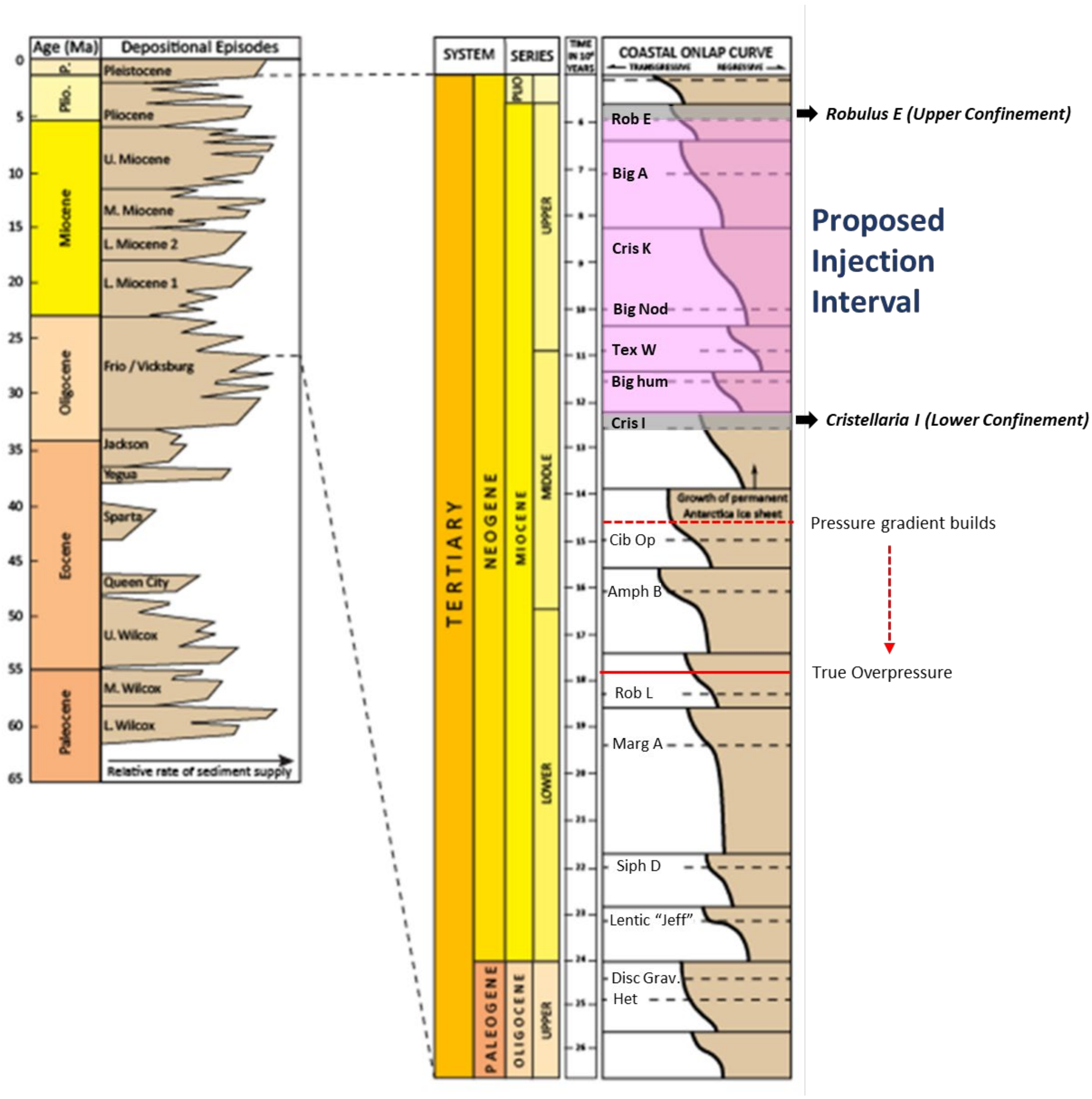

Figure 1-6 – Stratigraphic column of major Tertiary depositional episodes showing Miocene coastal onlap curve (right) with key benthic foraminifera annotated. The proposed confinement layers are highlighted in gray, and the proposed injection interval is highlighted in pink (modified from Meckel and Treviño, 2014).

Index fossils, often called biostratigraphic or paleontologic markers, break up the Miocene strata in sections associated with global eustatic highs. Figure 1-7 shows the proposed injection interval highlighted on a sequence stratigraphic chart. From oldest to youngest within the proposed injection interval (Middle to Upper Miocene), these include *Cristellaria I*, *Bigenerina humblei* (Big Hum), *Textularia W / Textularia stapperi*, *Bigenerina A*, and *Robulus E* (Rob E) (Hulsey, 2016). These benthic faunal markers recorded in shaley intervals during transgressive cycles are recognized by the U.S. Geological Survey (USGS) to "serve as fine-grained self-sealing units" for the sandy intervals below them (Roberts-Ashby, et al., 2014). The impermeable nature of these shales is further exemplified by the numerous oil and gas fields surrounding the study area, which produce from reservoirs with trapped hydrocarbons sealed in place by overlying shale beds.

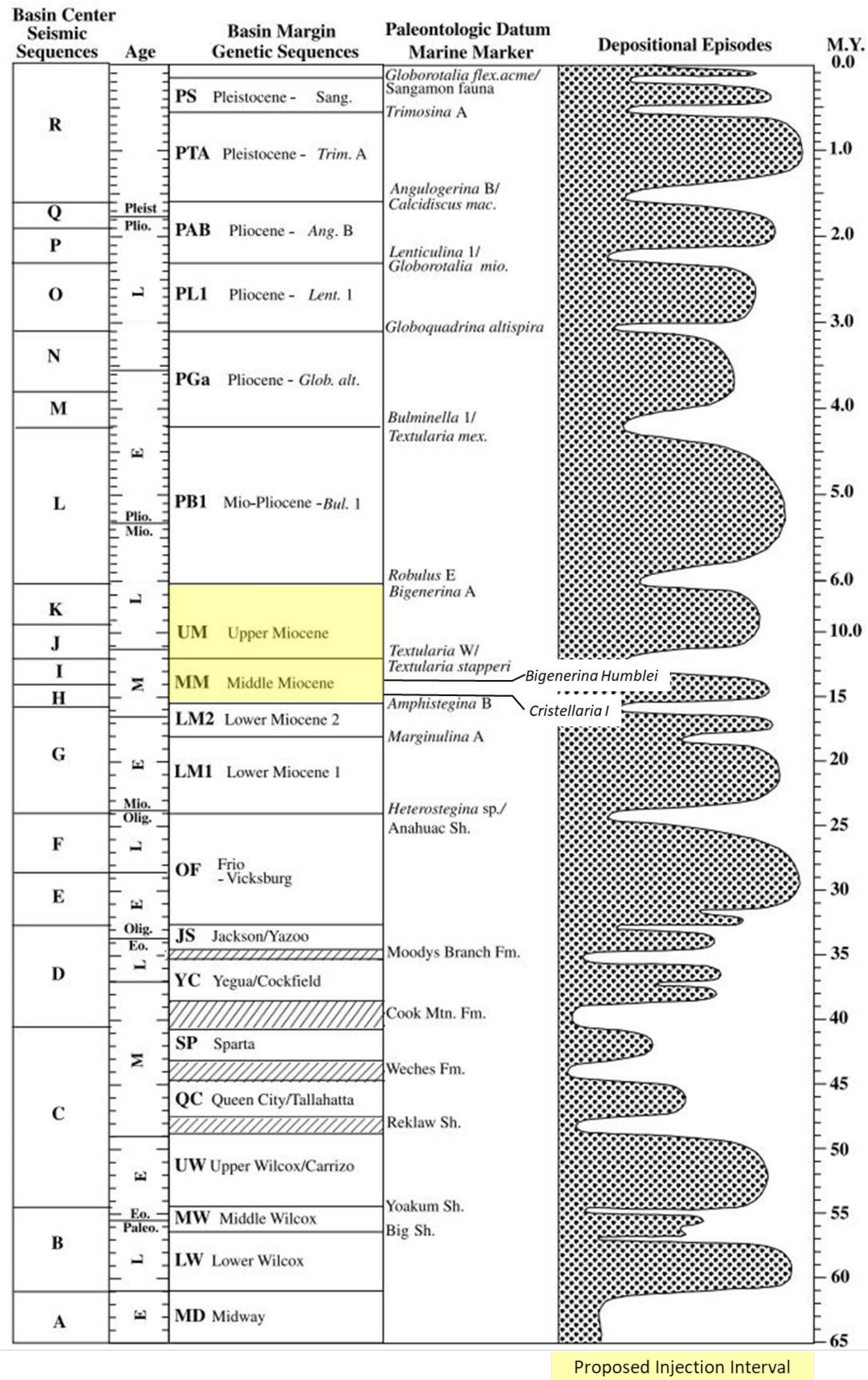

Figure 1-7 – Chronology of Gulf of Mexico Cenozoic genetic sequences and their bounding marine shale units and paleontologic markers. The proposed injection interval for this study is highlighted in yellow (modified from Galloway, Ganey-Curry, Li, and Buffler, 2000).

Lower Confining Zone: Cristellaria I Shale

The *Cristellaria I* (Cris I) is of Middle Miocene age, deposited approximately 15 m.y. The Cris I interval marks the transition of the section into deeper water environments. The Big Hum sand deposited conformably above the Cris I shale is recognized as the deepest correlative bed extending throughout the study area, with sands immediately below the shale bed tending to shale out (Vidrine, 1958). The Cris I shale ranges in thickness from 138 ft to 712 ft, with an average thickness of 324 ft in the Libra project area. Most of the thickness variability is due to a wedge effect of the shaling out of sands in this neritic environment, along with considerable thickening of the shale unit itself. The thickness change may have resulted from environmental changes, from shifts in the source of the sediments or from rapid subsidence—or a combination of these factors (Vidrine, 1958). Therefore, the Cris I shale is one of the better regional markers and an excellent lower sealing unit for CO_2 sequestration. This regionally extensive shale was deposited on top of *Amphistegina B* (Amph B) aged sediments.

Injection Zone: Upper and Middle Miocene Sandstones

The Upper and Middle Miocene section is the proposed injection interval for this permit application. This section was deposited approximately 5½–15 m.y. in cyclic transgressive-regressive environments with rich sediment supply from high-energy fluvio-deltaic depositional systems. The average thickness of the injection interval in the central portion of the study area is approximately 6,080 ft. The shared salt withdrawal mini-basins of offset salt domes (Bayou Couba, Bayou Des Allemands, and Paradis) set up a structural paleo-low (trough), highly capable of accumulating the rapid sedimentation of the mid- to late-Miocene. The Upper Miocene reservoirs in South Louisiana occur across an extensive depth range of 950 ft to 18,000 ft, with characteristic reservoir thicknesses for individual sand units of 15 ft to 300 ft; reservoir quality in these sands range from good to excellent, with effective porosities generally ranging from 20% to 35% and permeabilities from 50–2,500 millidarcies (mD) (Wu & Galloway, 2002).

Upper Confining Zone: Robulus E Shale

The upper confining zone proposed in this study is the Rob E shale. Regionally significant and laterally extensive, this shale was formed during a regional marine flooding event ending the Upper Miocene deposition and preceding the start of the Pliocene approximately 5½ m.y. The Rob E shale represents a transgressive sequence characterized by high eustatic sea levels leading to the deposition of regionally extensive fine-grained to silt-sized clay minerals, which make it a strong sealing unit for upper confinement. This shale bed varies in thickness, with an average thickness of 302 ft across the Libra project area. Above the Rob E shale is an undifferentiated Pliocene section, which is distinctly richer in net sand than the alternating sands and shales of the Upper and Middle Miocene intervals.

1.3 Site Geology

The area of review (AOR), as defined by the plume extents and critical pressure front from dynamic simulation, is located in St. Charles Parish, approximately 17 mi southwest of New Orleans and 6 mi northwest of Lake Salvador, as shown in Figure 1-8. The proposed injection wells, Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, are located in marshland, near mean sea level. Upon approval of this Class VI permit application, a shared surface pad will be built to host all three injector wells with a planned wellbore spacing of only 25 ft. Therefore, the site characteristics and rock properties are anticipated to be virtually indistinguishable among the three locations. For this reason, much of the forthcoming discussion is generalized to describe the "injection sites" or "project area" (i.e., not well-specific).

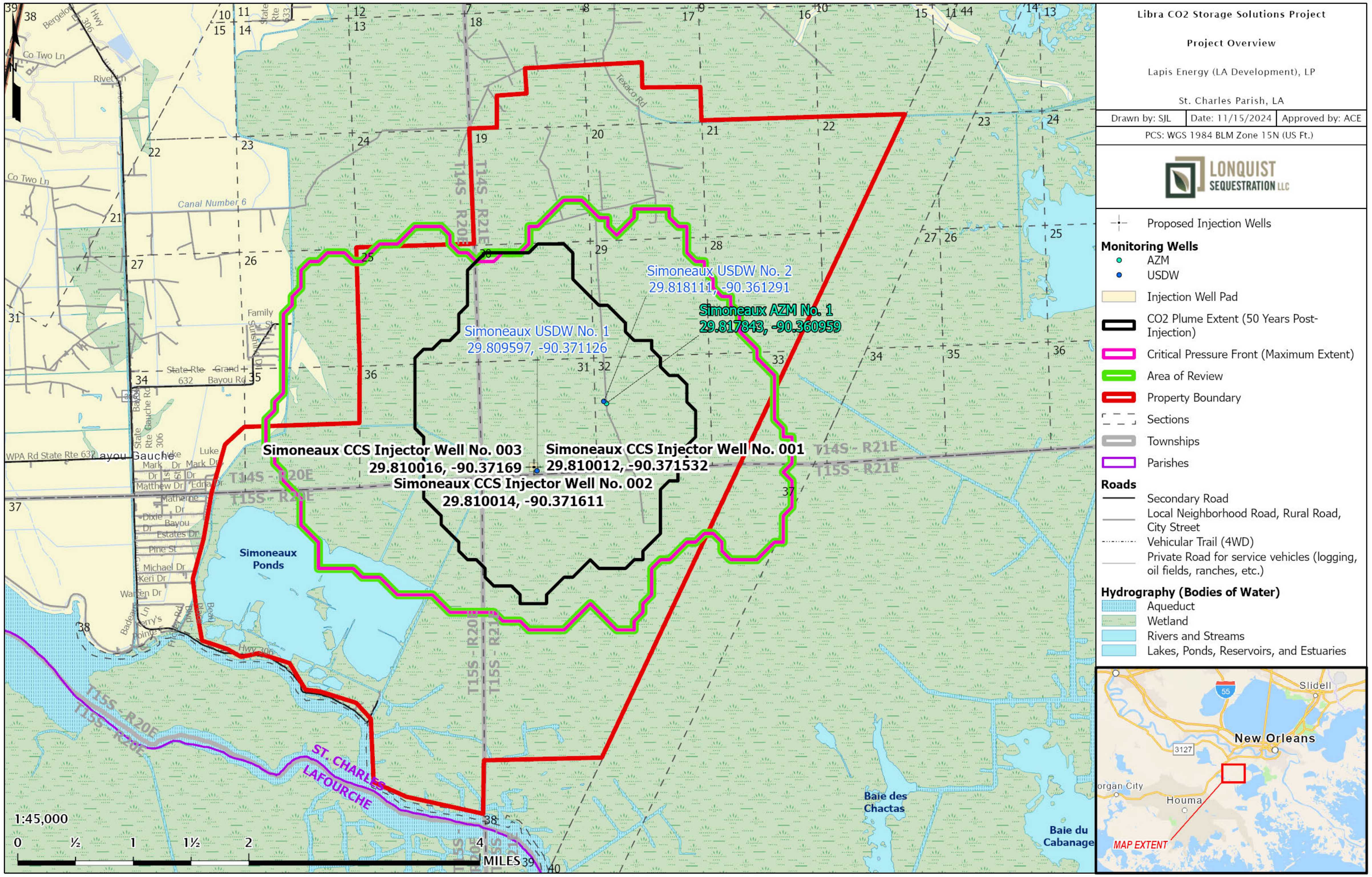

Figure 1-8 – Project Overview Map showing the modeled plume extents, pressure front, and property boundary in relation to water bodies, roadways, and major metropolitan areas.

Lapis proposes to amend, revise, and enhance all applicable interpretations, site characteristics, and accompanying models from the research conducted over the Libra project area, using a stratigraphic test well. To facilitate this effort, a Class V stratigraphic test well permit (application No. 45467) has been requested from the Louisiana Department of Energy and Natural Resources (LDENR). Upon issuance of the Class VI Order to Construct, the stratigraphic test well will be converted to an above-zone monitoring well, Simoneaux AZM No. 1. More information surrounding this is located in *Section 5 – Testing and Monitoring Plan*.

Provided in Table 1-1 is a list of wireline logs planned during the drilling of the proposed injection wells. The table includes projected top and base depths designed to provide specific data pertinent to the site characterization application. Data collection during drilling may alter the top and base depths of investigation in order to analyze the proposed target formations. Table 1-2 lists anticipated intervals of coring operations planned during the drilling of the proposed wells, to obtain mineralogical, petrophysical, mechanical, and geochemical data—to integrate into and further refine this site characterization.

Table 1-1 – Planned Wireline Log Intervals
*Contingent upon Simoneaux Strat Well No. 001 results

		Simoneaux Strat Well No. 001		Simoneaux CCS Injector Well No. 001		Simoneaux CCS Injector Well No. 002		Simoneaux CCS Injector Well No. 003	
		Surface Run 13.5 in. HD 9.625 in. CS	TD Run 8.75 in. OH	Surface Run 13.5 in. HD 9.625 in. CS	TD Run 8.75 in. OH	Surface Run 13.5 in. HD 9.625 in. CS	TD Run 8.75 in. OH	Surface Run 13.5 in. HD 9.625 in. CS	TD Run 8.75 in. OH
	Data	0–3,100 ft	3,100–10,070 ft	0–3,300 ft	3,300–9,975 ft	0–3,300 ft	3,300–8,010 ft	0–3,300 ft	3,300–6,295 ft
Open Hole	**Spontaneous Potential**	x	x	x	x	x	x	x	x
	Gamma Ray	x	x	x	x	x	x	x	x
	Density	x	x	x	x	x	x	x	x
	Neutron	x	x	x	x	x	x	x	x
	Resistivity	x	x	x	x	x	x	x	x
	Dipole Acoustic		x		x				
	NMR		x		x				
	Image log		x		x				
	Spectral Gamma		x		x				
	Pore Pressure	x	x		x				
	Fluid Sample	x	x		x				
	Stress Test		x		x				
	Sidewall Core		x		x				
	Zero Offset VSP		x		x				
Cased Hole	**Cement Bond**	x	x	x	x	x	x	x	x
	Temperature		x		x		x		x
	Pulse Neutron		x		x		x		x
	Casing Inspection		x		x		x		x

*HD –
CS –
OH – open hole
NMR – nuclear magnetic resonance
VSP – vertical seismic profile

Table 1-2 – Planned Core Intervals

	Simoneaux Strat Well No. 001			Simoneaux CCS Injector Well No. 001		
Stratigraphic Zone	**Core ID**	**Depth Interval (TVD ft)***	**Ft**	**Core ID**	**Depth Interval**	**Ft**
Upper Confining Layer (UCL)	1	3,290–3,320	30			
Upper Miocene (UM1)	2	3,850–3,910	60	1	**	60
Cristellaria K	3	5,790–5,880	90	2	**	60
Cristellaria K / Bigenerina Nodosaria	4	7,110–7,200	90			
Middle Miocene	5	8,580–8,670	90	3	**	60
Lower Confining Layer (LCL)	6	9,870–9,900	30			
Confining and Injection Layers	Rotary Sidewall Core (RSWC)		50	RSWC		100

*Final depths will be updated based on actual drilling results.
**Whole core is currently not planned in Simoneaux CCS Injector Well No. 001. However, based on whole core retrieval and core measurement results in Simoneaux Strat Well No. 001, Lapis in consultation with LDENR may later opt to take three 60-ft whole cores in the first injector.

General mineralogy and reservoir characteristics are first described in regional context from publicly available research articles and studies. When available, core data from offset wells are included. The structure and reservoir properties anticipated at the proposed well sites are then described on a more localized scale. These localized analyses are based on geologic data from offset wells used to generate structure maps, isopach maps, and supporting cross sections—as well as petrophysical analyses and modeling—to characterize the structural features and reservoir properties expected at the injection sites. Existing 3D seismic data was also used to interpret the structure and faulting, as well as guiding depositional fairways.

A type log—the Inexco Oil L B SIMONEAUX ET AL NO. 001 (SN 168952)—was selected to visually represent statements made in this application, due to its proximity to the proposed injection wells and consistent log characteristics over the injection and confining zones. This well was logged over a single openhole run on September 23, 1980. Formation tops and depths to the upper confining zone, injection zone, and lower confining zone as logged in this well are listed in Table 1-3. Figure 1-9 is a stratigraphic column of lithologies, formations, and depths as encountered in the well. Formation top nomenclature, defined by Lapis for this site characterization, is listed in the Group/Fm./Mbr. column of Figure 1-9 at the TVD depths in which they were logged in the type log (SN 168952).

Table 1-3 – Injection and Confining Zones Encountered in L B SIMONEAUX ET AL NO. 001 (SN 168952)

System	Formation Name	Injection/Confinement	Formation Top-Bottom (TVD ft)	Thickness (ft)
Upper Miocene	Rob E shale	Upper Confinement	3,163–3,533	370
Upper and Middle Miocene	Sandstones (undifferentiated)	Injection	3,533–9,514	5,981
Middle Miocene	Cris I shale	Lower Confinement	9,514–9,801	287

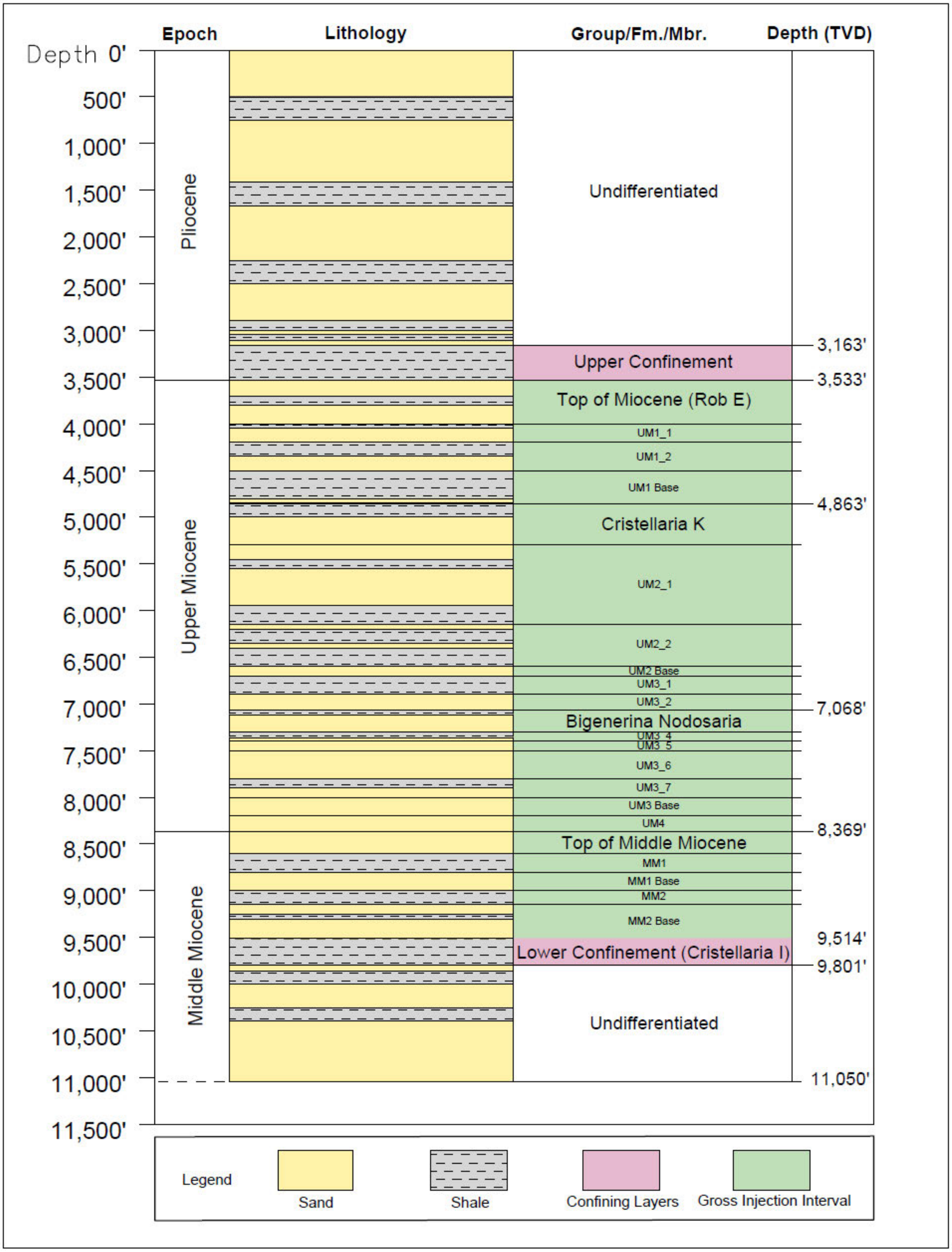

Figure 1-9 – Stratigraphic Column Encountered in SN 168952

1.3.1 Upper Confining Zone

The Upper Miocene genetic sequences display similar facies distribution patterns, reflecting deposition during an extended episode of relatively stable sediment dispersal and paleogeography. The depositional episode, depicted in the map in Figure 1-10, records extensive margin offlap, primarily centered on the Mississippi dispersal axes, that began immediately following the *Textularia W / Textularia stapperi* flooding and was terminated by a regional flooding event associated with the Rob E biostratigraphic top (Galloway, 2000).

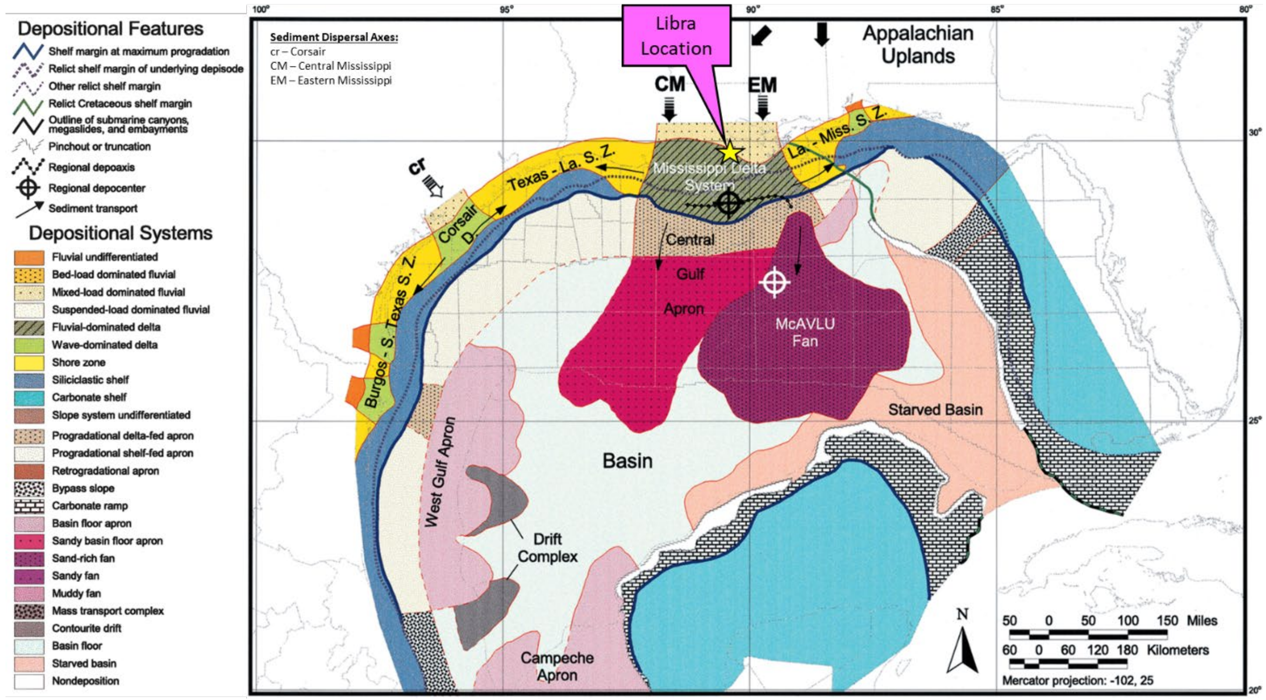

Figure 1-10 – Paleogeography of the late Miocene (12–6.4 m.y.) depositional episode, with the Libra project location represented by the yellow star (modified from Galloway, 2000).

The Rob E upper confining zone at the Miocene–Pliocene boundary represents a cyclic on-shelf highstand and transgressive systems tract (Hentz & Zeng, 2003). This upper confining shale is highly correlative regionally and easy to pick from well to well within the Libra project area. It ranges in thickness from 149 ft to 420 ft in the project area, with an average interval thickness of 302 ft.

Fifty-seven wells were petrophysically analyzed by Lapis to compute Vshale curves and model petrophysical rock type (PRT), porosity, and permeability across the greater project area. Three of these wells are displayed in a cross section in Figure 1-12, which illustrates the continuity and high shale content of the upper confinement. A reference basemap showing the location of these wells is shown in Figure 1-11. From left to right, these include the JOESPH RATHBORNE LD LBR CO NO. 001 (SN 48783), the L B SIMONEAUX ET AL NO. 001 (SN 168952), and the VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687).

The average Vshale is 80.4% across 294 ft of gross upper confinement interval in the JOESPH RATHBORNE LD LBR CO NO. 001 (SN 48783); the average Vshale is 82.0% across 370 ft of gross upper confinement interval in the L B SIMONEAUX ET AL NO. 001 (SN 168952); and the average Vshale is 74.0% across 375 ft of gross upper confinement interval in the VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687). Note that, within the gross upper confining zone, some thin channel sandstones and siltstones exist that do not exhibit lateral continuity, and therefore pose no risk to vertical CO_2 leakage pathways. The continuity and consistency of the Rob E shale bed makes this interval an extremely strong sealing candidate for CO_2 sequestration.

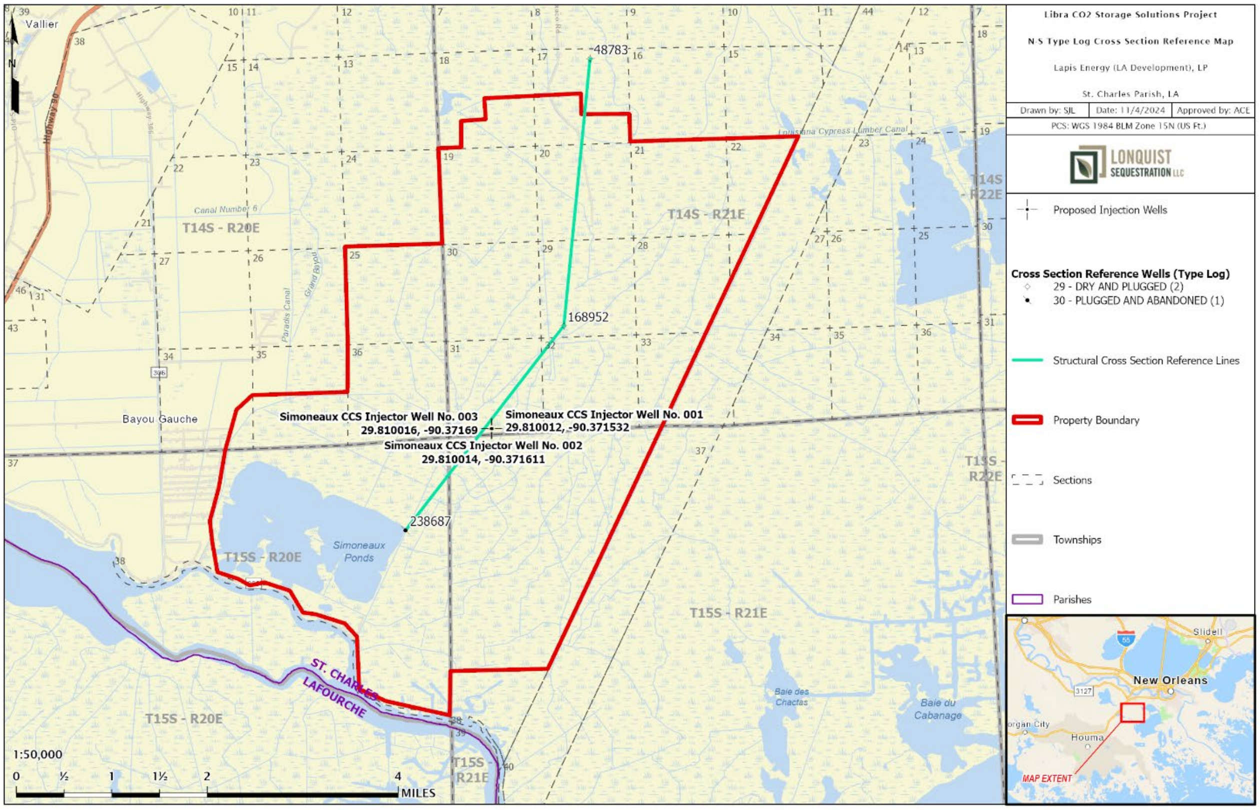

Figure 1-11 – Reference basemap showing the location of the cross section line shown in Figure 1-12 and Figure 1-15.

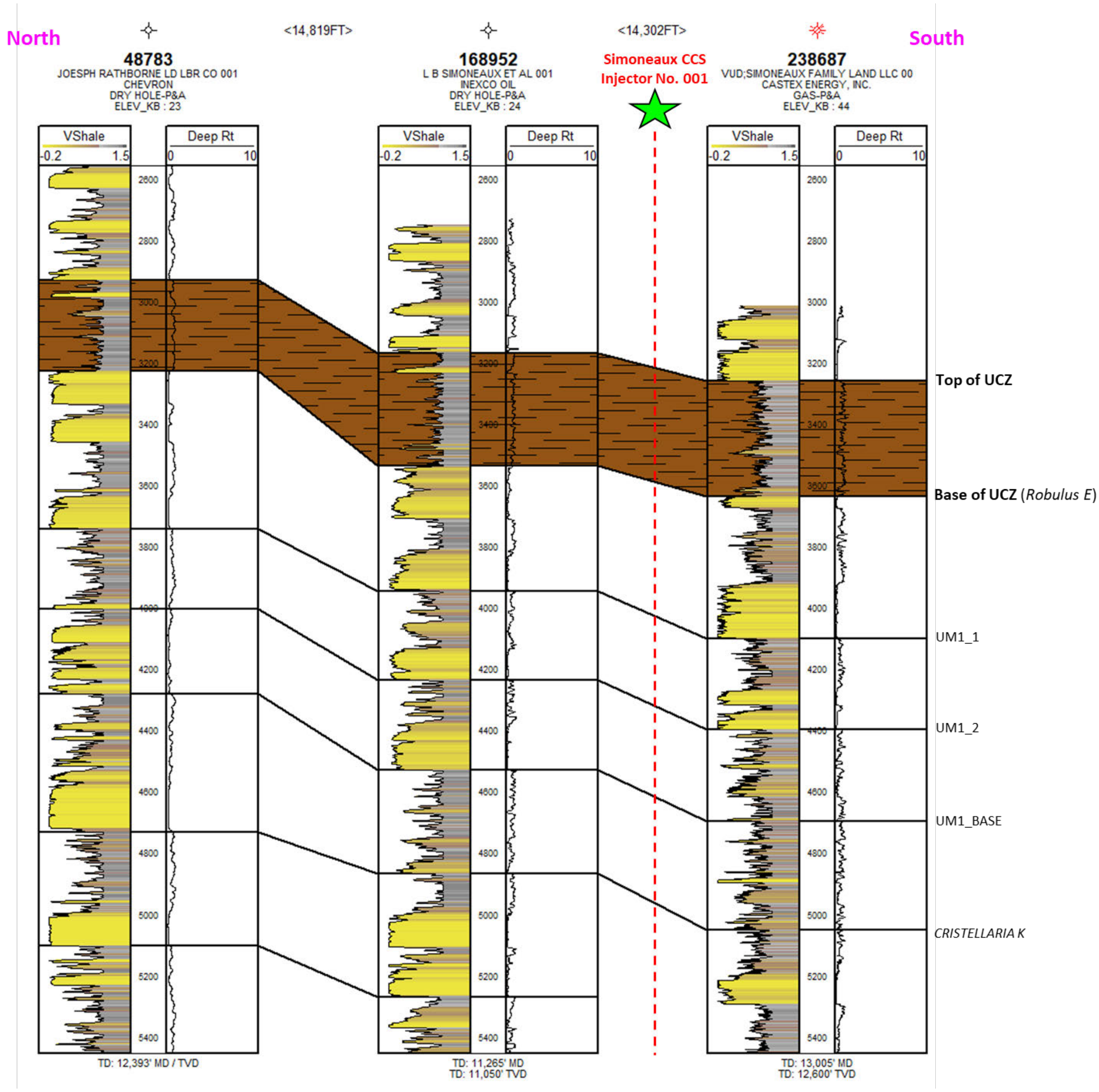

Figure 1-12 – Three-well petrophysical cross section with color-filled Vshale curves illustrating high clay content in the Rob E shale, the upper confining zone. Note: The Underground Source of Drinking Water is 2,000 ft shallower than the top of the upper confinement at 1,222 ft TVD, discussed in *Section 1.10.2*.

1.3.2 Injection Zone

The injection zone comprises the entire Upper Miocene and the majority of the Middle Miocene. The Upper and Middle Miocene depositional episodes are bounded by regional-marine transgressive deposits and maximum flooding surfaces where several benthic foraminiferal markers are recorded (Combellas-Bigott & Galloway, 2006). These include, from youngest to oldest within the injection zone: Rob E*, Bigenerina A, Bigenerina B, Cristellaria K, Textularia L, Cibicides carstensi, Bigenerina nodosaria, Textularia W,* Big Hum*,* and Cris I. Figure 1-13 shows the lithostratigraphic and biostratigraphic subdivisions of the proposed Miocene injection interval, along with their corresponding maximum flooding surfaces and benthic markers.

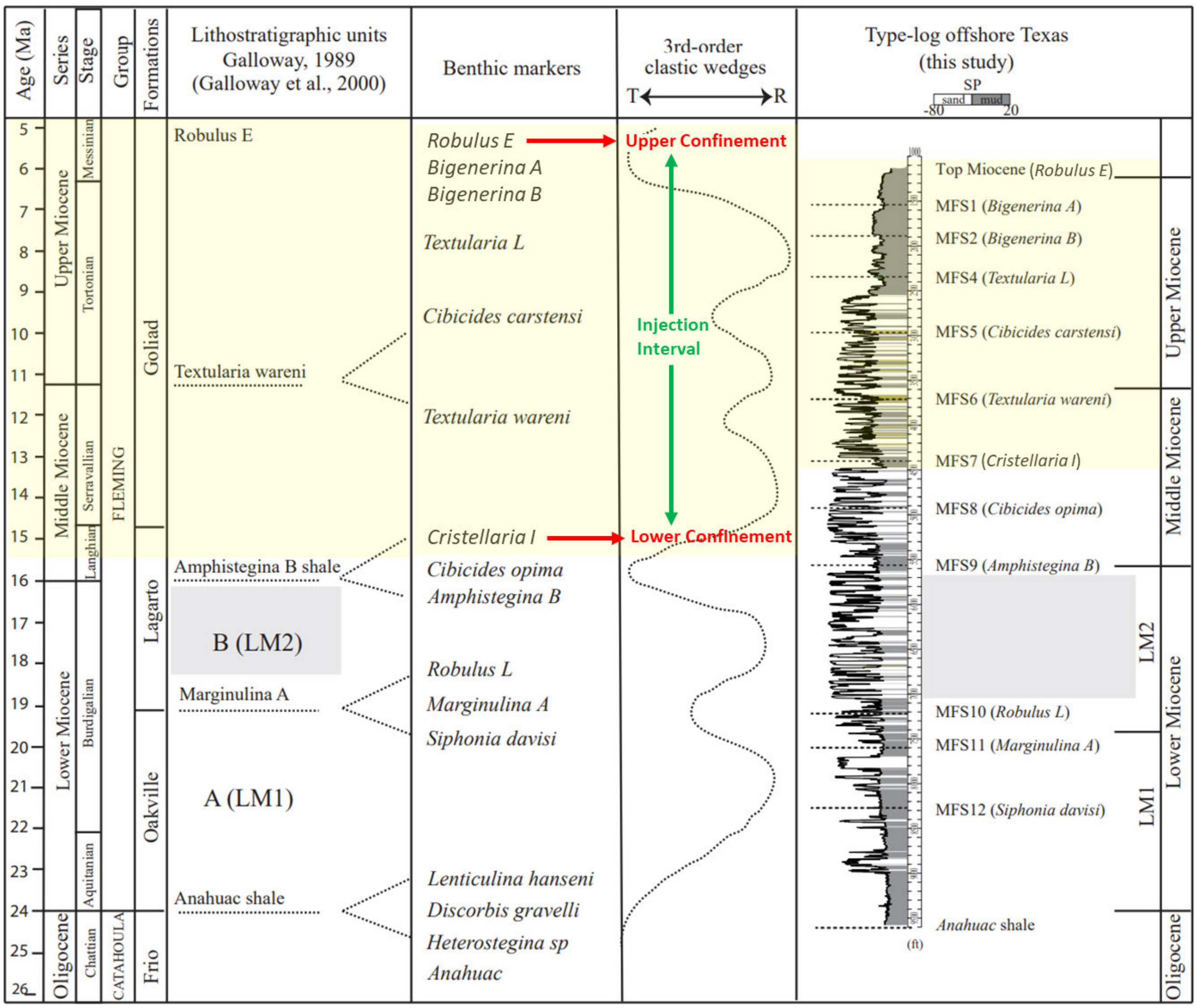

Figure 1-13 – Correlation chart showing lithostratigraphic and biostratigraphic subdivisions of the Miocene section in the northwest shelf of the Gulf of Mexico, with the proposed confinement and injection zones annotated (modified from Olariu et al., 2019).

Upper and Middle Miocene deposition in the Libra project area was dominated by the Mississippi Delta system. The strata were deposited in a variety of settings, including a distributary channel, delta plain, delta, interdeltaic embayment, continental shelf, and upper continental slope (Galloway, Ganey-Curry, Li, & Buffler, 2000). Late Middle Miocene and early Upper Miocene display similar facies distribution patterns regionally, reflecting deposition during an extended episode of relatively stable sediment dispersal and paleogeography, with little modification for nearly 7 million years. The Upper Miocene depisode records extensive margin offlap, primarily centered on the Mississippi dispersal axes, that began immediately following the *Textularia W / Textularia stapperi* flooding and was terminated by a regional flooding event associated with the Rob E biostratigraphic top (Galloway, Ganey-Curry, Li, & Buffler, 2000).

Salt-related structural provinces largely influenced the location and configuration of sediment accumulation in depocenters supplied by the Mississippi delta system (Combellas-Bigott & Galloway, 2006). Three large salt domes proximal to the project area (Bayou Couba, Bayou Des Allemands, and Paradis) provided an excellent mini-basin depocenter in between for accumulating Miocene sediment. The location of these fields in relation to the project area was shown in Figure 1-5.

Primary lithologies within the Upper and Middle Miocene sections are interbedded sandstones, siltstones, and shales. In a Department of Energy sponsored evaluation of the Miocene section as a candidate for carbon sequestration in the Gulf of Mexico basin, core samples within the correlative Miocene injection zone revealed fine- to coarse-grained sandstones with interbedded mudstones and siltstones (Meckel & Trevino, 2014).

Due to a shared sediment source and depositional setting, mineralogy of the entire injection interval will be similar. Mineralogy of the Upper and Middle Miocene is dominated by quartz, K-spar, plagioclase, and rock fragments, with minimal contributions from clays and calcite and trace amounts of glauconite and pyrite. A more specific breakdown of these mineralogic components was obtained from thin section analyses of sandstone samples taken from the TWEEDEL UNIT V NO. 001 (SN 48231) in St. Landry Parish, Louisiana (Table 1-4). Based on being the most proximal, this well was selected from the Bureau of Economic Geology (BEG) thin section database and sampled at a comparable depth and geologic section of the wells available. While the deeper samples collected in this well (10,305–10,383 ft) may have a slight diagenetic impact on core analysis compared to the burial depths of the Miocene at the Libra project sites (3,504–9,854 ft), limited availability of mineralogy research forced a reliance on this data for the time being. Upon issuance of the Class VI Order to Construct, core data will be taken from the stratigraphic test well and subsequently undergo X-ray diffraction to obtain a more accurate localized mineralogy at the proposed injection site.

Table 1-4 – Mineralogy data collected in TWEEDEL UNIT V NO. 001 (SN 48231) in St. Landry Parish. Mineralogy data was obtained from the BEG thin section database.

Mineral Constituent	% by Volume
Quartz	74.4%
Quartz Cement	4.7%
Plagioclase	4.4%
K-feldspar	4.1%
Rock fragments–Volcanic	3.7%
Rock fragments–Siliceous	3.6%
Clays (Kaolinite, Illite, Smectite)	2.4%
Calcite (Fe)	1.5%
Pyrite	0.7%
Muscovite	0.2%
Glauconite	0.2%

An openhole log from the type log, the Inexco Oil L B SIMONEAUX ET AL NO. 001 (SN 168952), is displayed in Figure 1-14. A Vshale log was calculated through petrophysical means from the spontaneous potential (SP) curve to determine the varying clay content through the proposed injection section. This Vshale curve can be seen in Track 1 (left), with a geocolumn shading applied to help visualize the varying shale content. A deep resistivity curve (90-inch (in.) depth of investigation) is plotted in Track 2 (right). The injection interval begins at the top of the Rob E marker and includes all strata down to the Cris I. Lapis-defined nomenclature for correlative formation tops are shown to the right of the type log. The gross interval thickness of the injection zone in the LB SIMONEAUX ET AL NO. 001 depicted in Figure 1-14 is approximately 5,981 ft, with an estimated 3,933 ft of net sand targeted for completion and injection; this yields an average net-to-gross of 65.7%.

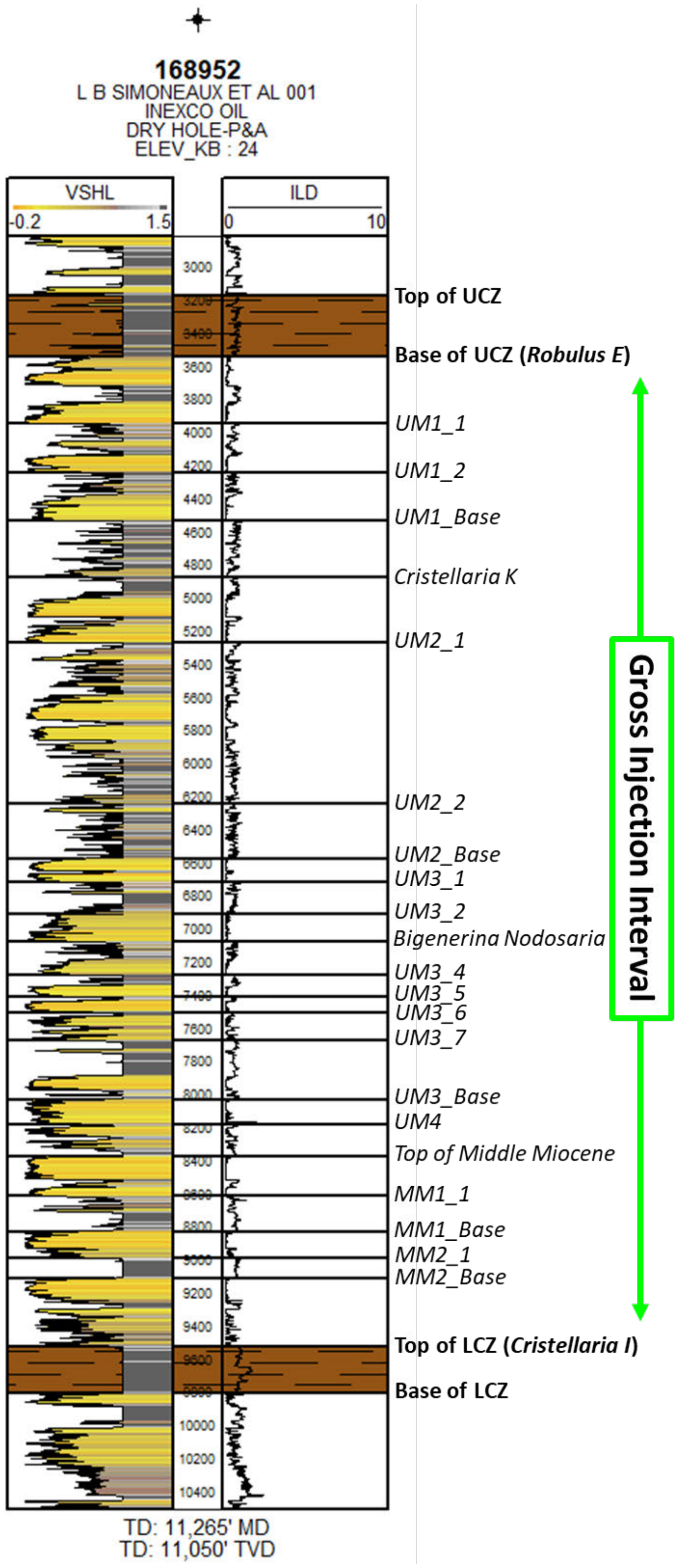

Figure 1-14 – Openhole log of offset well L B SIMONEAUX ET AL NO. 001 (SN 168952) depicting the injection interval and upper and lower confinement zones.

1.3.3 Lower Confining Zone

A common phenomenon of Gulf Coast sequence stratigraphy where hiatal surfaces separate transgressive or retrogradational deposits of one sequence from the progradational deposits of the succeeding sequence is exemplified by the Cris I shale regionally across the Libra project area. Intermittent sediment deposition commonly occurs across areas of the flooded depositional platform; however, terrigenous sedimentation rates are extremely low, and extended time intervals are recorded by thin, stratigraphically and compositionally distinctive marker beds (Galloway, 1989). The Cris I represents the last episode of marine flooding before entering a much more sand-rich, progradational environment of the Middle and Upper Miocene. The regionally extensive maximum flooding surfaces of *Cibicides opimas* and Amph B age were deposited below the Cris I, providing the utmost confidence in the sealing nature and regional extents of the shales at the base of the proposed injection zone.

Similar to the Rob E shale, the Cris I shale bed is highly correlative and easy to pick regionally. The Cris I shale "wedge" described in *Section 1.2.1* varies from 200–1,200 ft thick in and beyond the project area. The base of the lower confining zone was conservatively picked at the first encounter of a 10-ft or greater sand interval. However, the extremely low net-to-gross (i.e., high Vshale) in the underlying 2,000 ft of section ensures that the lower confinement is not restricted to solely relying on the first shale interval as depicted in Figure 1-15.

The same three wells used for the upper confinement cross section are shown in Figure 1-15, this time centered on the lower confining zone. The reference basemap showing the location of these wells was shown in Figure 1-11. From left to right, these include the JOESPH RATHBORNE LD LBR CO NO. 001 (SN 48783), the L B SIMONEAUX ET AL NO. 001 (SN 168952), and the VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687).

The average Vshale is 87.3% across 224 ft of gross lower confinement interval in the JOESPH RATHBORNE LD LBR CO NO. 001 (SN 48783); the average Vshale is 94.5% across 299 ft of gross lower confinement interval in the L B SIMONEAUX ET AL NO. 001 (SN 168952); and the average Vshale is 82.7% across 483 ft of gross lower confinement zone in the VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687). The continuity and consistency of the Cris I shale bed makes this interval an extremely strong sealing candidate for CO_2 sequestration.

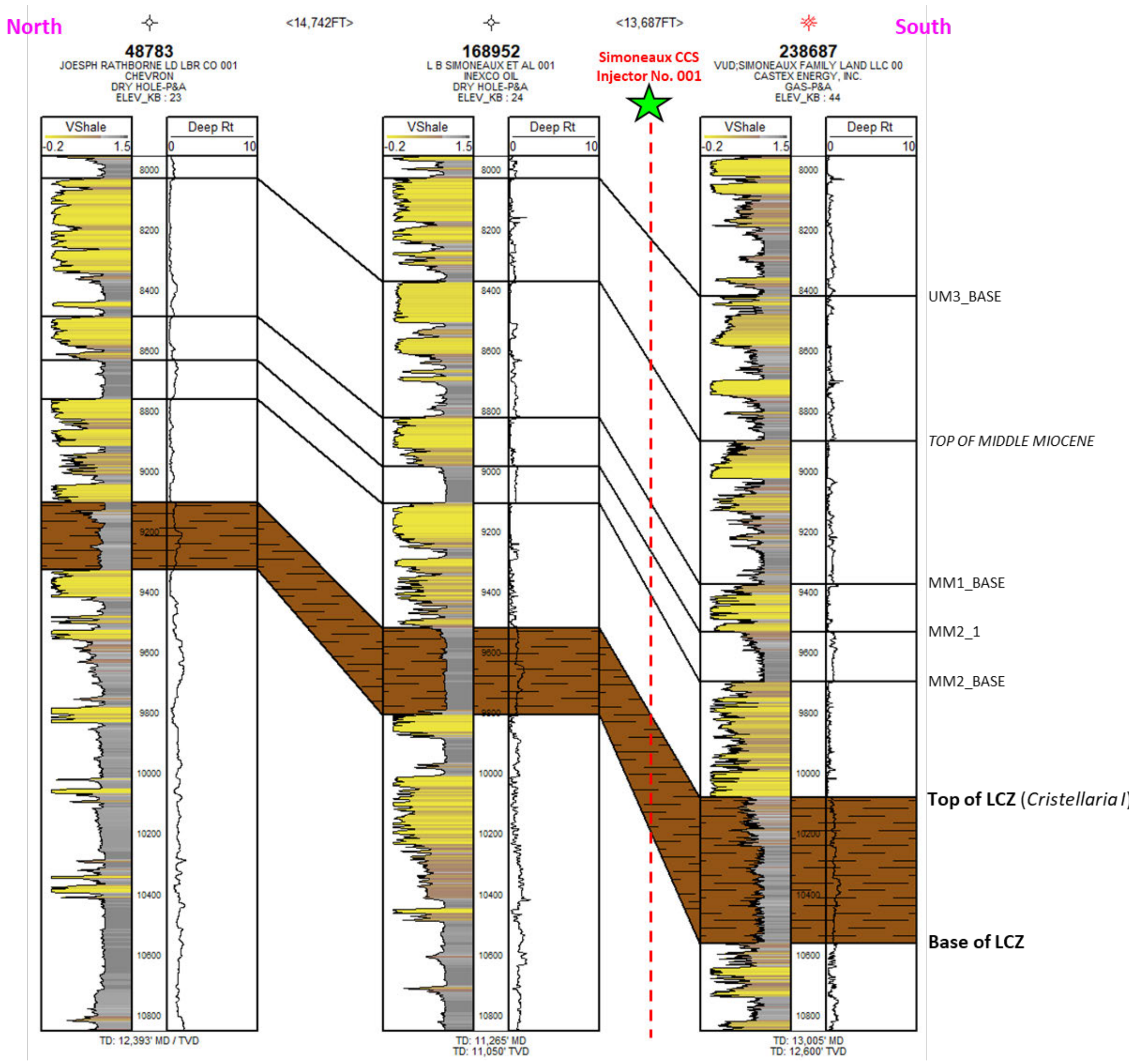

Figure 1-15 – Three-well petrophysical cross section with color-filled Vshale curves illustrating high clay content in the Cris I shale, the lower confining zone.

1.4 Petrophysics

Petrophysical evaluation was conducted on 57 offset wells with openhole log data, enabling the derivation of continuous curves for shale volume (Vshale), porosity, permeability, and petrophysical rock types. Vshale was calculated from baseline-shifted SP curves, while effective porosity was estimated using Vshale and a depth-dependent maximum porosity model. The calculated porosity was quality-checked by comparison with density-neutron derived porosity, where available. A permeability correlation was developed using regional Miocene core data, incorporating samples from the BEG's Northern GOM Sandstone Reservoir Quality Database

(GOMRQ)[1] and sidewall cores from an offset well; reports with this sample data are presented in *Appendix B*. Petrophysical rock types were defined using a Vshale cutoff criteria. The following sections detail the well log inventory and petrophysical workflow.

1.4.1 Well and Log Data Inventory

Details on the offset wells used in the petrophysical analysis are provided in Table 1-5.

Table 1-5 – The 57 offset wells with digital log data used for petrophysical evaluation.

Serial No.	Well Name and No.	Resistivity	SP	Gamma	Neutron	Density
53063	WILLIAM H TALBOT 001	X	X			
48783	JOSEPH RATHBORNE LD LBR CO 001	X	X			
73869	RATHBORNE LAND & LUMBER 002	X	X			
54182	JOSEPH RATHBORNE LD & LBR CO 003	X	X			
76172	LYDIA B SIMONEAUX ET AL 007	X	X			
47529	L B SIMONEAUX SWD 003	X	X			
68811	LYDIA B SIMONEAUX ET AL SWD 011	X	X			
87029	LYDIA B SIMONEAUX ET AL 012	X	X			
81236	WATERFORD OIL CO 001	X	X			
68317	SIMONEAUX 013	X	X			
60108	WATERFORD OIL COMPANY A 002	X	X			
33280	S J SIMONEAUX 001	X	X			
19717	SL 0348 001		X			
100790	SIM 10 SU C;T R PLATT 001-D	X	X			
108450	WILLIAM H TALBOT ET AL 002	X	X			
125786	ST CHARLES LD & TRUST CO C 001	X	X			
134633	RATHBORNE LAND CO INC 001	X	X			
142882	SIM 10 RA SUA;SIMONEAUX 017	X	X			
152158	SL 6184 001	X	X			
152640	MITCHELL & NEELY 001	X	X			
164763	RATHBORNE LAND COMPANY INC 001	X	X			
167807	LYDIA B SIMONEAUX ET AL 021	X	X			
186913	L B SIMONEAUX 002	X	X			
168952	L B SIMONEAUX ET AL 001	X	X	X	X	X
180305	L B SIMONEAUX 001	X	X			
193508	W R WHITE ET AL 001	X	X			
194435	ST CHARLES PH SCHL BD 001	X	X	X	X	X

[1] https://store.beg.utexas.edu/reports-of-investigations/3893-ri0289.html

Serial No.	Well Name and No.	Resistivity	SP	Gamma	Neutron	Density
197891	RATHBORNE LAND COMPANY INC 001	X	X			
237039	VUA;SIMONEAUX FAMILY LAND LLC 002	X	X			
238687	VUD;SIMONEAUX FAMILY LAND LLC 005	X	X	X	X	X
250321	SIMONEAUX FAMILY LAND LLC 001	X		X	X	X
250809	SIMONEAUX FAMILY LAND LLC A 001	X		X		
250810	SIMONEAUX FAMILY LAND LLC 002	X		X		
251479	SELLERS HEIRS 001	X				
78858	JOSEPH RATHBORNE LAND CO INC 001	X	X			
75831	LYDIA B SIMONEAUX ET AL 015	X	X			
236901	VUB;SIMONEAUX FAMILY LAND LLC 001	X	X	X	X	X
237172	VUC;SIMONEAUX FAMILY LAND LLC 003	X	X	X	X	X
97884	JOS RATHBORNE LAND CO INC 001	X	X			
61848	W H TALBOT ETAL 001	X	X			
92455	W H TALBOT ETAL 001	X	X			
83940	JOS RATHBORNE LAND & LUMBER CO 001	X	X			
85381	JOESPH RATHBORNE LD LBR CO INC 001	X	X			
85381	JOESPH RATHBORNE LD LBR CO INC 001	X	X			
96089	J RATHBORNE L & L CO INC 001	X	X			
64758	WATERFORD OIL COMPANY 001		X			
59256	WATERFORD OIL CO B 001	X	X			
114452	WATERFORD OIL CO 001	X	X			
85846	WATERFORD OIL CO B 001-D	X	X			
60445	DELTA SEC CO INC 088	X	X			
49051	IRELAND FEE 001	X	X			
99536	JOS RATHBORNE LD CO INC 001	X	X			
117891	RATHBORNE LND & LBR CO 001	X	X			
174198	MITCHELL & NEELEY 001	X	X			
207279	MITCHELL & NEELY 001	X	X			
199376	RATHBORNE LAND CO 001	X	X			
250965	EMC FEE 002	X		X	X	X

1.4.2 Shale Volume (Vshale)

Baseline shifts were applied to the SP log to eliminate SP drift with depth and to set the reading to near-zero across the shales. Figure 1-16 shows histograms of the SP log before and after the baseline shift for an illustrative group of offset wells in the analysis.

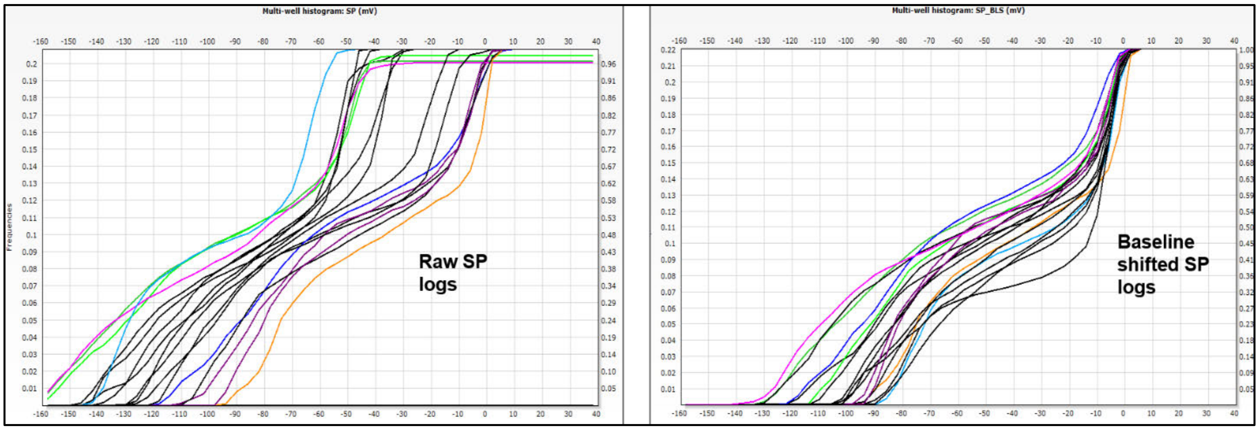

Figure 1-16 – Histograms of raw and baseline shifted SP logs for an illustrative group of offset wells in the analysis.

Vshale was computed from the baseline-shifted SP logs using Equation 1:

(Eq. 1)

$$Vshale = \frac{(SP - SP_{sand})}{(SP_{shale} - SP_{sand})}$$

The SP values for clean sand (SP_{sand}) and shale (SP_{shale}) were selected zone-wise, accounting for potential changes to SP end points due to varying water resistivity and multiple logging runs.

1.4.3 Porosity

Estimated effective porosity (PHIEST, φ_{eff}) was then calculated using the Vshale log and a depth-dependent PHIMAX in Equation 2:

(Eq. 2)

$$\emptyset_{eff} = \emptyset_{max} * (1 - Vshale)$$

The maximum porosity (PHIMAX, $\emptyset_{max}$) represents the maximum clean sand porosity and linearly decreases with depth, representing the Gulf Coast Miocene compaction trend.

An example of calculated Vshale, PHIMAX, and PHIEST for an illustrative type well, LYDIA B SIMONEAUX ET AL 15 (SN 75831), is shown in Figure 1-17. It can be noted that the value of PHIMAX is approximately 37% at a depth of 3,500 ft and 31% at a depth of 8,500 ft.

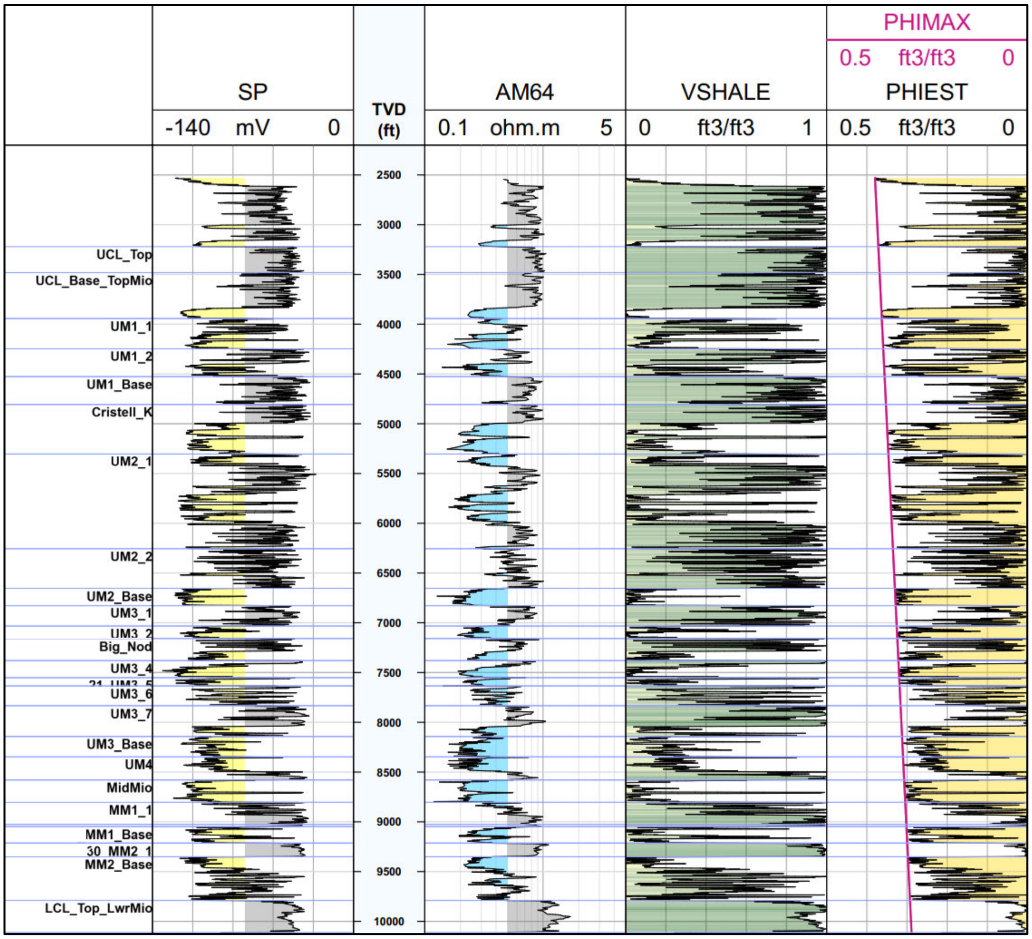

Figure 1-17 – Calculated Vshale, PHIMAX, and PHIEST from LYDIA B SIMONEAUX ET AL 15 (SN 75831)

A quality check of the PHIEST curve was conducted by overlaying the computed PHIEST with the PHIE curve—calculated from density-neutron porosity logs, where available. Three wells near the proposed storage site had sufficient density-neutron data over the proposed injection intervals: SIMONEAUX FAMILY LAND LLC NO. 001 (SN 250321), VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687), and EMC FEE NO. 002 (SN 250965). Figure 1-18 shows an example of good agreement between the calculated PHIEST and density-neutron porosity in VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687).

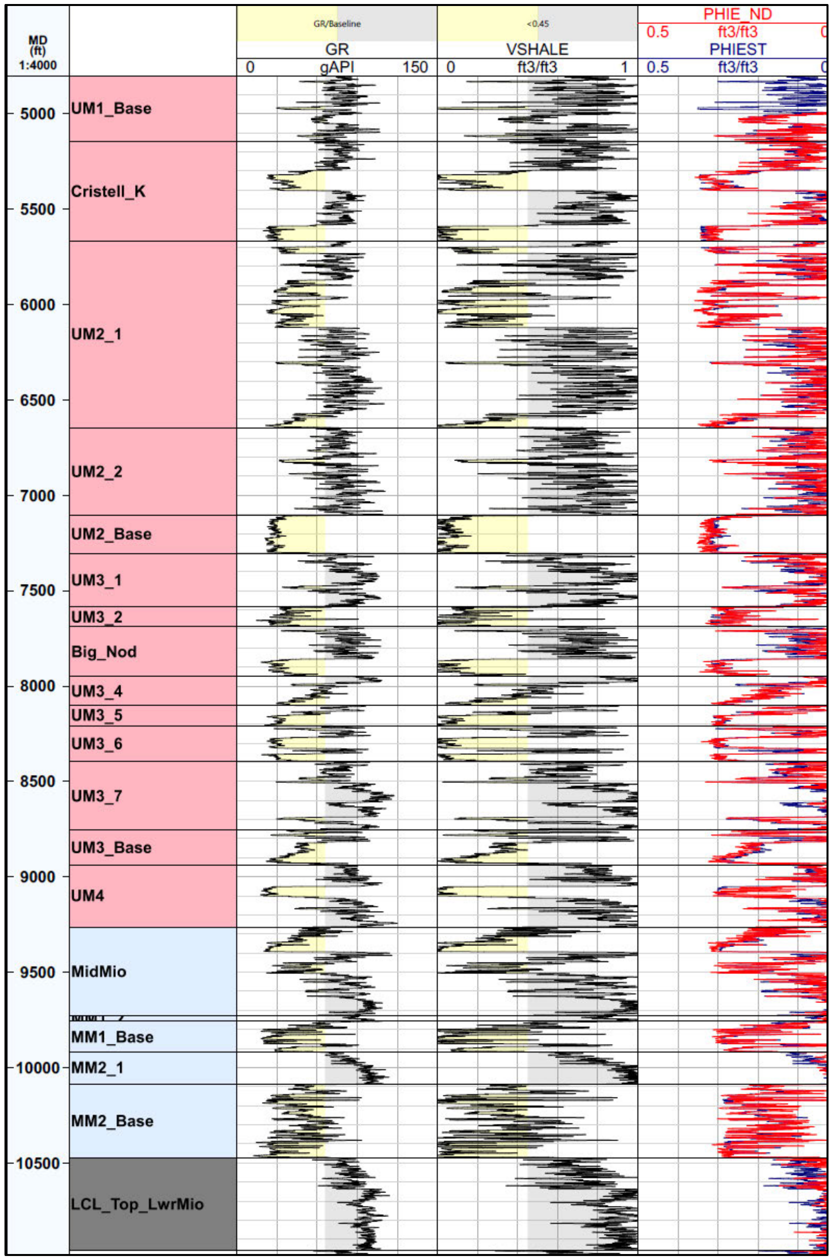

Figure 1-18 – Comparison of density-neutron porosity, PHIE_ND (red) and PHIEST (blue), derived from SP-porosity relationship, in well VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687).

1.4.4 Permeability

A permeability correlation was derived using 414 Miocene core porosity and permeability data points from the GOMRQ. The data points were from 24 offset wells located within a 50-mi radius of the model area and selected from samples taken at depths of less than 10,000 ft. Additionally, sidewall core data from one offset well, SL 7323 NO. 001 (SN 159950), located approximately 22 mi northeast of the proposed storage site, was also used. Figure 1-19 shows the location of the

24 wells from the GOMRQ and SL 7323 NO. 001 (SN 159950), the data from which were used to derive the permeability correlation.

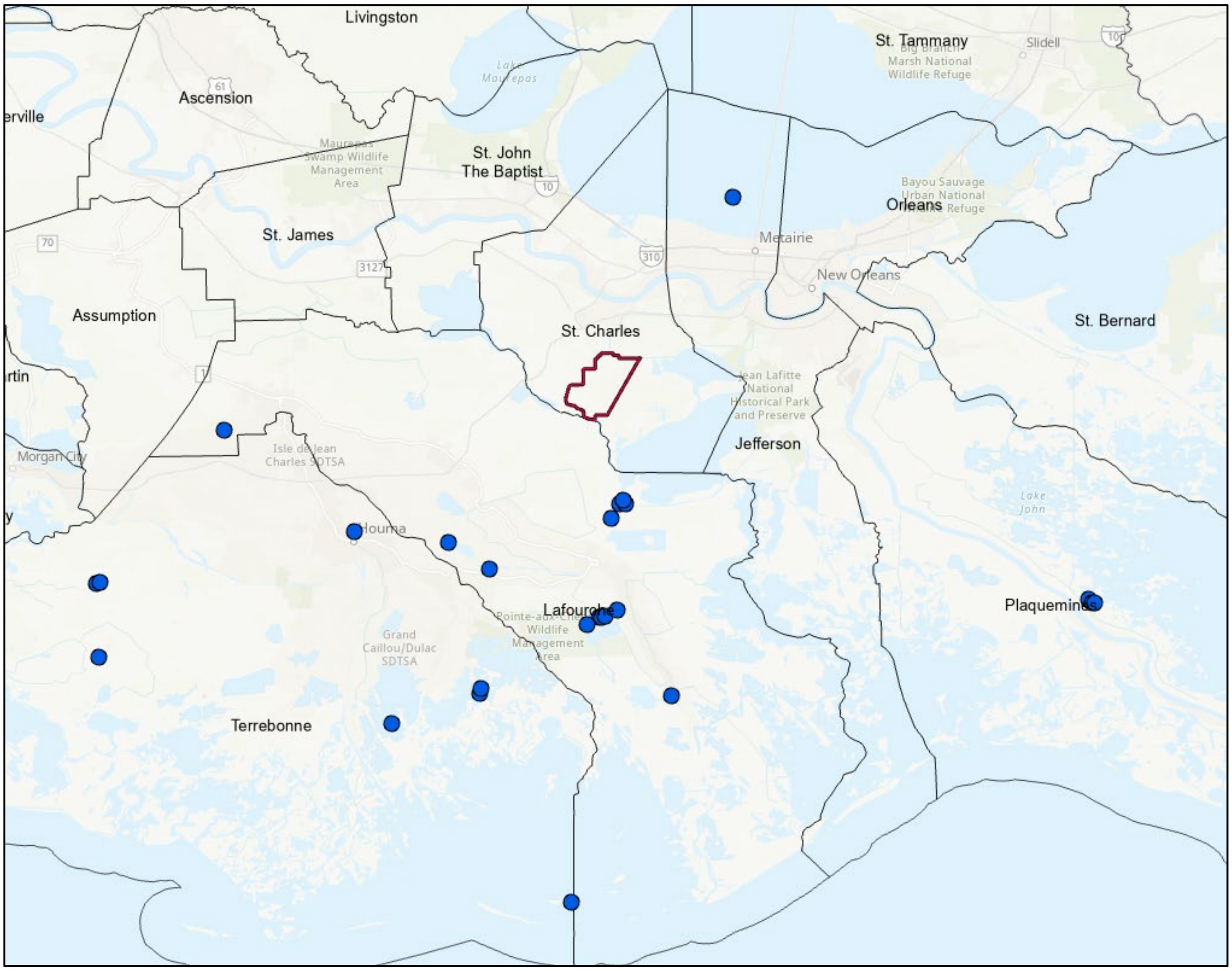

Figure 1-19 – Locations of offset well data used to derive permeability correlation relative to the Libra project site in St Charles Parish.

Figure 1-20 shows a crossplot of core porosity and permeability sourced from the data set detailed above. The permeability equation derived from its relationship to porosity is shown in Equation 3.

(Eq. 3)

$$K(mD) = 1e - 16 * \Phi^{12.435}$$

The core data spans a wide range of porosity values enabling the depiction of likely permeability ranges within the injection intervals.

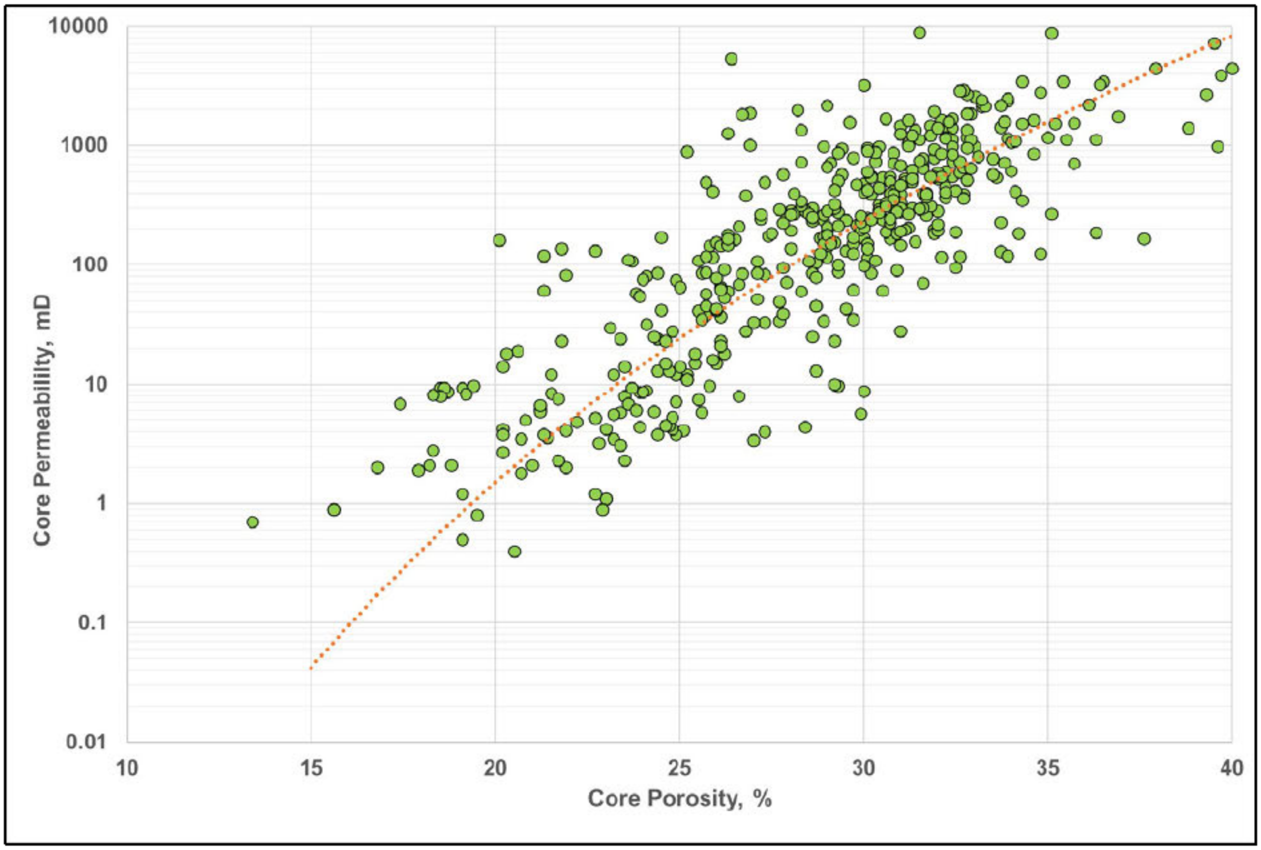

Figure 1-20 – Porosity vs. permeability scatterplot of 414 samples from the BEG GOMRQ and 62 sidewall core samples from SL 7323 NO. 001 (SN 159950).

1.4.5 Petrophysical Rock Type Log

A PRT log, subsequently used in geocellular modeling and rock property distributions, was calculated using the Vshale log as shown in Table 1-6.

Table 1-6 – Definition of Petrophysical Rock Type Log

PRT	Vshale Criteria	Lithology
0	>0.7	Shale
1	<= 0.7	Sand + Silt

Modeled facies and rock types will be refined after acquisition of data from the Class V stratigraphic test well, specifically core descriptions, mineralogy and petrophysical measurements.

1.4.6 Petrophysical Characteristics of the Injection and Confining Zones

The following section details the petrophysical characteristics, specifically the porosity and permeability distribution in the upper confining zone (UCZ), injection zone (IZ), and lower confining zone (LCZ). The statistical distributions were summarized from the petrophysical analysis of offset wells. Some statistics (i.e., net-to-gross, percent of gross interval, etc.) require curves spanning the entire subject interval for an accurate depiction. Therefore, wells with partial coverage over a respective zone were omitted as input for generating these statistics. Additionally, the PRT log was used as a filter to better characterize the zones' injection vs. confinement capabilities.

Shales (PRT-0) are expected to be clay-rich in this depositional environment, acting as a barrier and not contributing to flow; therefore, PRT-0 was assigned a uniform permeability of 0.001 mD. Backeberg et al. (2017) indicate that typical shale permeability ranges from 0.1–100 nanodarcies (nD). This range is 2 to 4 magnitudes lower than the constant 0.001 mD assigned to shales (PRT-0) in the geocellular model.

1.4.6.1 Upper Confining Zone

Figure 1-21 is a cross section displaying Vshale, effective porosity, and permeability across the Rob E shale interval. The location of the cross section line is displayed on the reference map at Figure 1-11. From left to right, the offset wells include the JOESPH RATHBORNE LD LBR CO NO. 001 (SN 48783), the L B SIMONEAUX ET AL NO. 001 (SN 168952), and the VUD;SIMONEAUX FAMILY LAND LLC NO. 005 (SN 238687). The Vshale curve is shaded to correspond with lithology from zero (clean sand) on the left to 1 (pure shale) on the right. The effective porosity (PHIE) scale is from 50% (left) to 0% (right). Permeability (PERM) is shown on a logarithmic scale from 0.001–10,000 mD, from left to right.

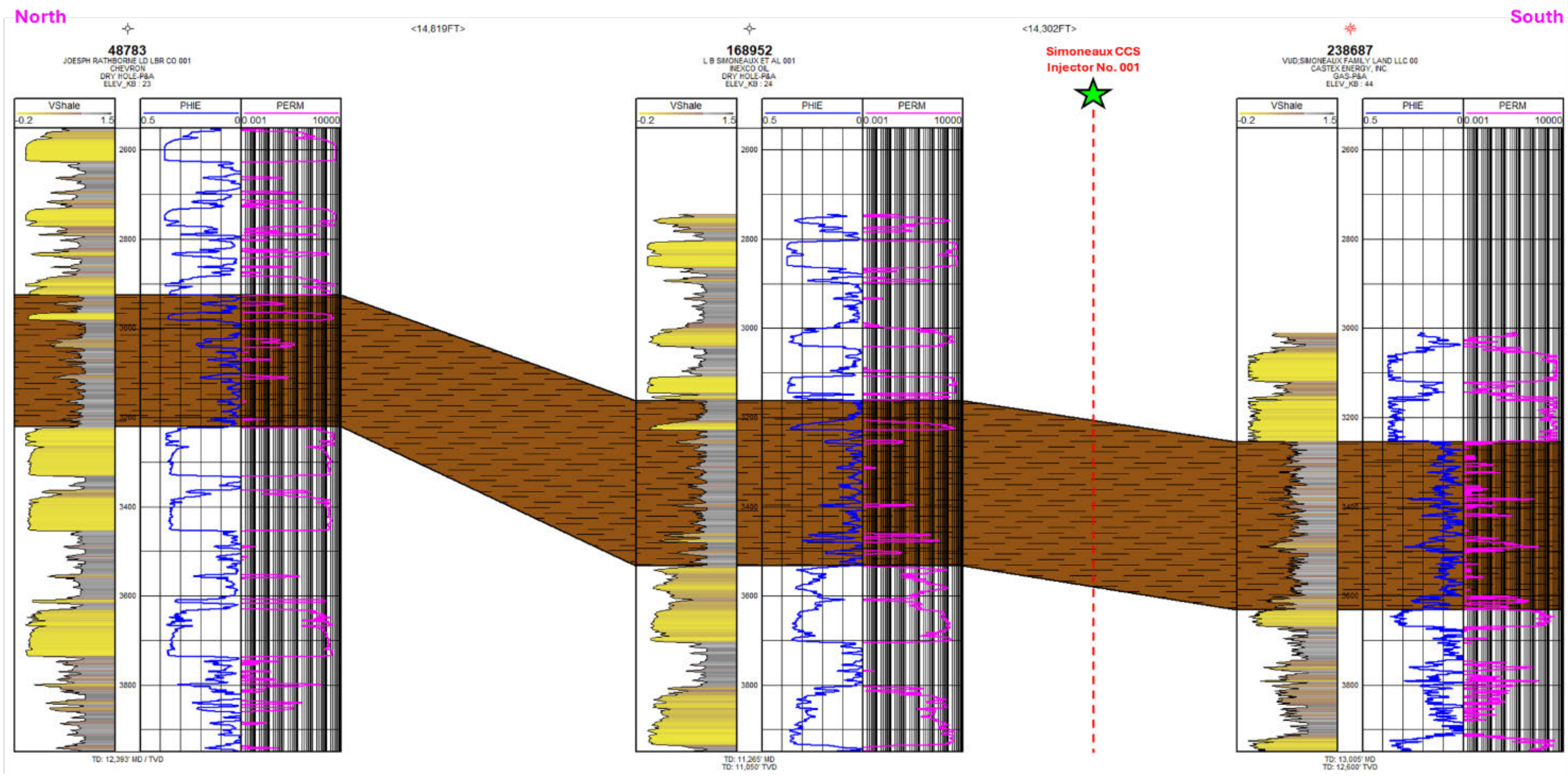

Figure 1-21 – Three-well type log cross section showing calculated petrophysical log curves centered on the Rob E UCZ. Tracks from left to right include calculated shale volume (Vshale), effective porosity (PHIE), and calculated permeability (PERM).

An average of 246 ft of net shale (PRT-0) over 302 ft of gross UCZ section yields a net-to-gross of more than 80% shale—excellent for confinement capabilities. The average effective porosity of PRT-0 in the Rob E shale across all applicable petrophysical logs is 3.5%. As described in the introduction for this section, shales (PRT-0) are assigned a constant permeability of 0.001 mD.

1.4.6.2 Injection Zone

Figure 1-22 is the same three-well cross section depicted in Figure 1-21, here centered on the Upper and Middle Miocene injection zone. The location of this line is displayed on the reference map at Figure 1-11.

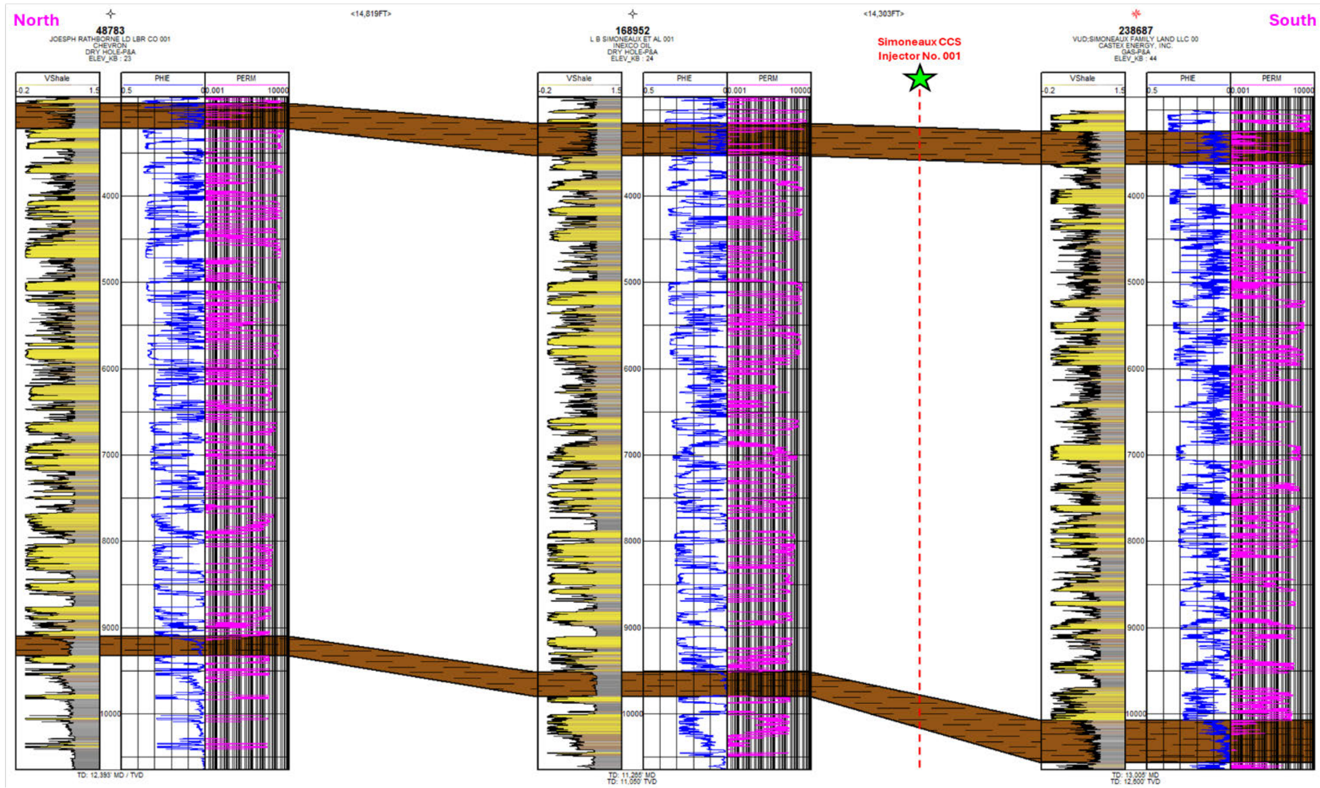

Figure 1-22 – Three-well type-log cross section showing calculated petrophysical log curves centered on the Upper and Middle Miocene IZ. Tracks from left to right include calculated shale volume (Vshale), effective porosity (PHIE), and calculated permeability (PERM).

An average of 3,712 ft of net sand (PRT-1) over 6,056 ft of gross IZ section yields a net-to-gross of 61.3% injection quality sand, with the remaining 38.7% net shale (PRT-0) serving as compartmentalizing seals between individual sand packages. The average effective porosity of PRT-1 (sands + silt lithology) in the IZ across all applicable petrophysical logs is 24.4%. The permeability of these injection-quality sands is most commonly in the range of 10–2,500 mD, with an average of 283 mD.

1.4.6.3 Lower Confining Zone

Figure 1-23 is the same three-well cross section depicted in Figures 1-21 and 1-22, here centered on the Cris I lower confining zone. The location of this cross section line is also displayed on the reference map at Figure 1-11.

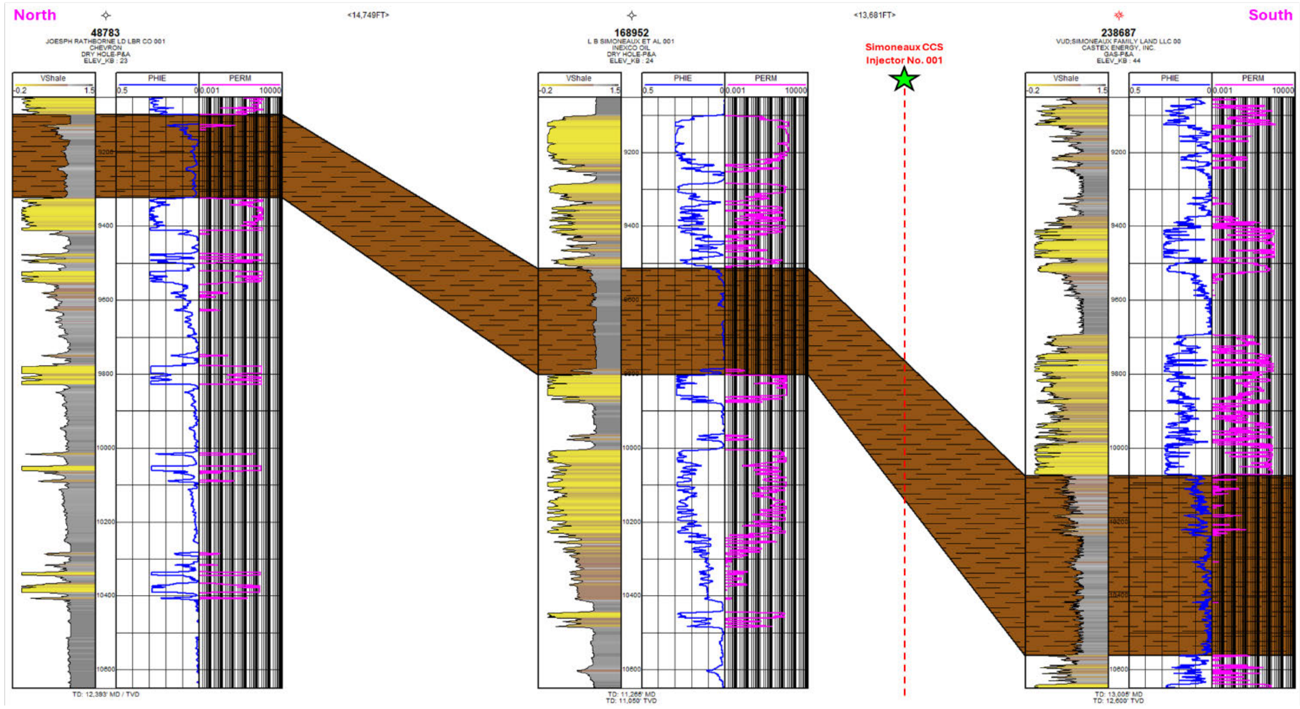

Figure 1-23 – Three-well type log cross section showing calculated petrophysical log curves centered on the Cris I LCZ. Tracks from left to right include calculated shale volume (Vshale), effective porosity (PHIE), and calculated permeability (PERM).

An average of 266 ft of net shale (PRT-0) over 324 ft of gross LCZ section yields a net-to-gross of more than 80% shale, making it a very strong confining zone. The average effective porosity of PRT-0 in the Cris I shale across all applicable petrophysical logs is 2.9%. As described in the introduction for this section, shales (PRT-0) are assigned a constant permeability of 0.001 mD.

1.5 Geologic Structure

Structural bed dip and faulting were identified and mapped utilizing abundant well control and 3D seismic data in the study area. Structure maps, cross sections, isochore maps, and other supporting geologic exhibits are presented in *Appendix B*.

1.5.1 3D Seismic Data

Approximately 42 square miles (sq mi) of 3D seismic data from the Gheens 3D (2007 Merged Reprocessing) survey was licensed from Seismic Exchange Inc. (SEI) by Lapis and integrated into all geologic interpretations herein. Figure 1-24 shows the licensed data area in relation to the Libra project area and well control. The main survey parameters are listed in Table 1-7.

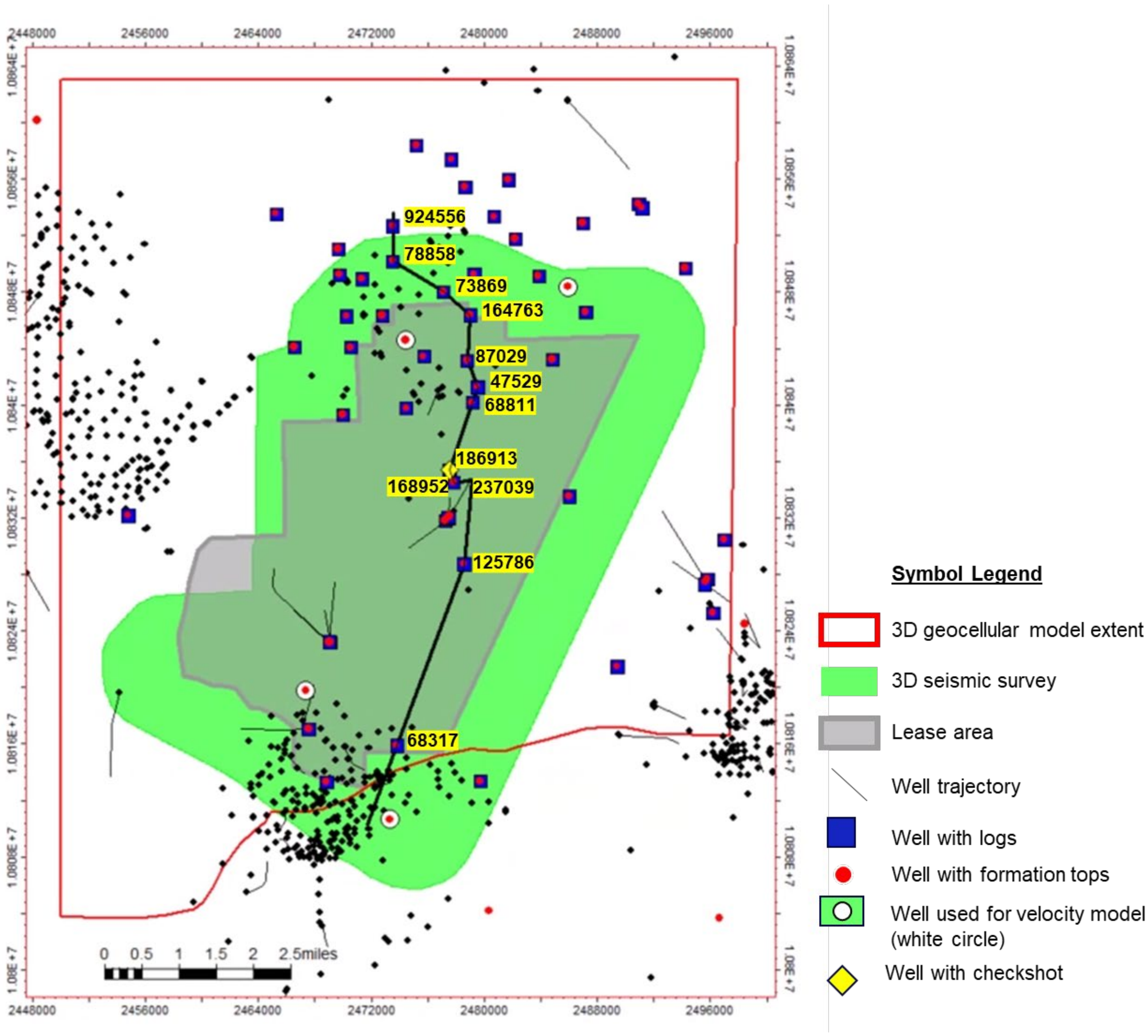

Figure 1-24 – Basemap of the proposed Libra project area showing the location of the licensed 3D seismic, geomodel extents, well data, and cross section line shown in Figures 1-28, 1-30, and 1-31.

Table 1-7 – Gheens 3D Merge Seismic Survey Parameters

Merged Survey Name	**Gheens 3D Merge**
Processing Year	2007
Licensed Area	42 mi^2
Migration	Pre-Stack Time Migration
Input Survey Name	**Gheens 3D**
Square Mile	267.21
Shot Date	May 2006
Shot By	Veritas DGC Land
Bin Size	110 ft x 110 ft
Record Length / Sample Interval	10 seconds / 2 milliseconds
Maximum Far Offset	25,490 ft
Fold	56
Energy Source	Pentolite
Source Line Interval / Spacing	311 ft / 1,245 ft
Receiver Line Interval / Spacing	220 ft / 1,760 ft
Input Survey Name	**Paradis 3D**
Square Mile	62.00
Shot Date	June 1999
Shot By	PGS – Petroleum Geo-Services
Bin Size	83 ft x 165 ft
Record Length / Sample Interval	10 seconds / 2 milliseconds
Max. far offset	17,786 ft
Fold	40
Energy Source	Pentolite
Source Line Interval / Spacing	330 ft / 990 ft
Receiver Line Interval / Spacing	165 ft / 1,650 ft

The Gheens 3D Merge data set was a merge of Gheens 3D (2006), Houma Embayment 3D (2002), Paradis 3D (1999), Raceland 3D (1996), and Summer Island 3D (1994). The licensed data was constrained to just where the Gheens 3D and Paradis 3D surveys overlapped as shown in Figure 1-25(a); hence, the survey parameters for the other three surveys were not included in Table 1-7. Excellent fold coverage exists over the entire licensed area, as shown in Figure 1-25(b). Fold coverage is important as it is indicative of high-quality seismic data with minimal noise and reprocessing artifacts.

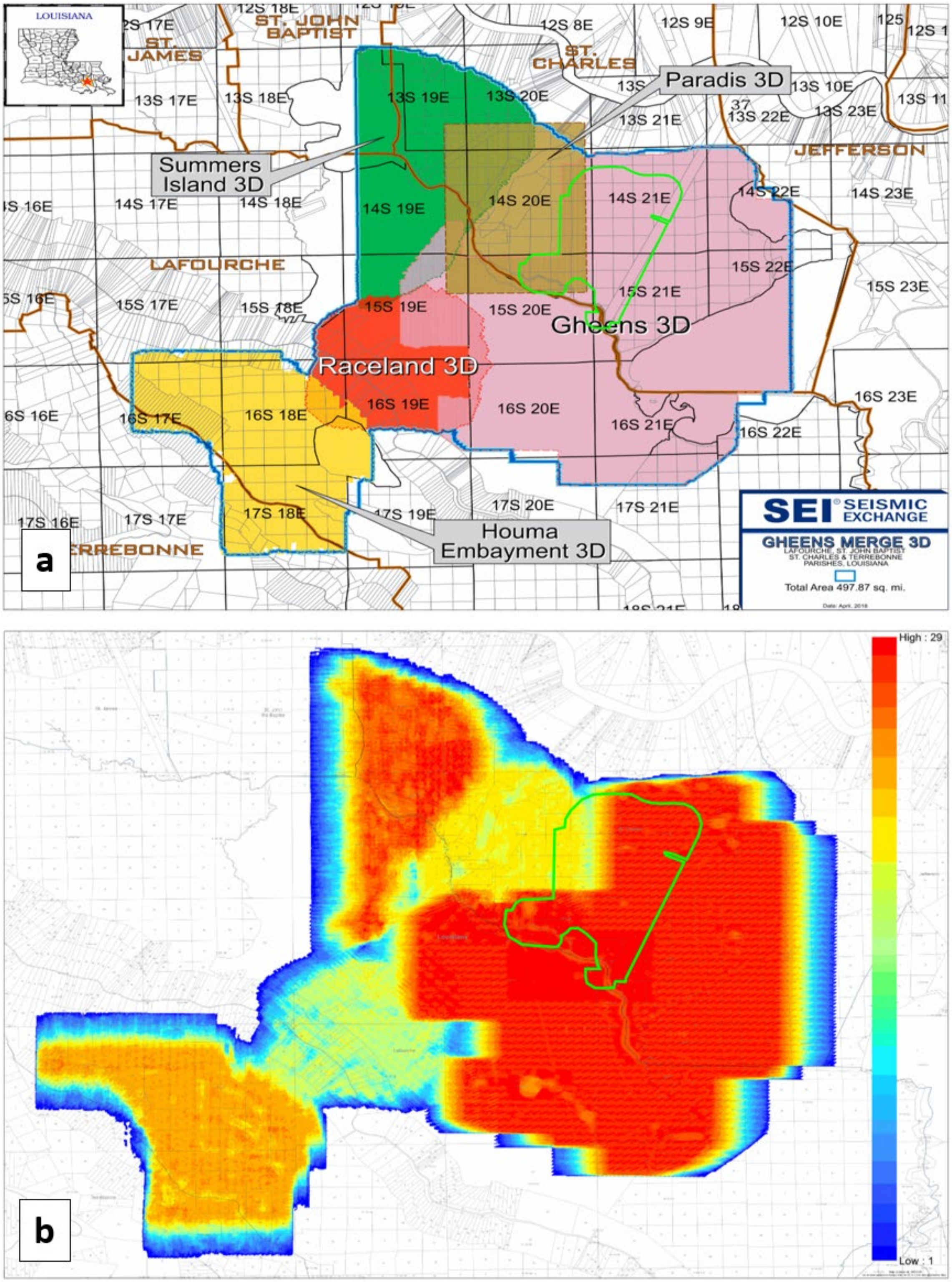

Figure 1-25 – (A) Survey constituents that comprise the SEI Gheens 3D (2007 Merged Reprocessing) data set, and (B) the fold coverage of the merged data, with hotter colors representing high-fold coverage and cooler colors representing poor coverage. The 39 sq mi licensed area is shown by the lime green outline.

The 3D seismic data, which images the subsurface based on velocity and density contrasts, was combined with geologic formation tops from abundant subsurface well control, to map a sequence of Upper and Middle Miocene-age strata approximately 6,500 ft thick, from the Rob E down to the Cris I. The resulting maps represent formation depths and any discontinuities (e.g., faults); the integrated depth-structure maps for the top of the injection and base of the injection interval are shown in Figures 1-26 and 1-27, respectively. Moreover, seismic data along with the well logs contribute to the understanding of subsurface lithology (petrophysical rock types and distribution of rock properties), discussed in more detail in *Section 1.6*, on the geocellular model.

Seismic data quality is good, with fold coverage and offsets sufficient to map the entirety of the injection interval, from the shallowest occurrence of the top of the upper confinement (+/- 2,650 ft) to the deepest occurrence of the base of lower confinement (+/- 10,900 ft) in the project area. Nine faults were identified and mapped on the seismic data. Of the nine faults, three faults were interpreted in the north and included in the geocellular model. The three northern faults are deep and cut the lower confining zone—the Cris I shale—but only extend approximately 500 ft up into the lower part of the injection interval, before they die out. The throw, however, is not large enough to fully offset the lower confining zone. Six faults were seismically interpreted in the south, consisting of one large, east-west striking, southward-dipping synthetic fault with four antithetic faults terminating onto it, and a north-south striking, westward-dipping normal fault. The large synthetic fault was used as part of the model boundary, therefore the four antithetic faults were not included in the geocellular fault model. The two seismically interpreted faults in the south, which were included in the model, extend through the full injection zone, including the top confining zone—the Rob E shale.

Additional faults were included outside of the seismic coverage based on regional maps. The seismic interpreted faults were extended beyond the seismic coverage if warranted by the regional maps. All interpreted faults that cut through the upper and lower portion of the injection zone are displayed in Figures 1-26 and 1-27, respectively, and the additional structure maps are presented in *Appendix B*. The faults are described in greater depth in the discussions of the geocellular model (*Section 1.6*) and the fault slip potential (FSP) model (*Appendix K*).

The proposed injection well locations are approximately 2.4 mi south of the northern fault at the top of the lower confining layer and 3.1 mi north of the southern fault. Bed dips over the plume area are gentle and remain consistent throughout the injection interval, with a southerly primary dip direction ranging from about 2° at the lower confining zone (Cris I shale) and flattening to about 0.5° at the upper confining zone (Rob E shale). The subsurface interpretation does not indicate significant changes in the thickness of the injection or confining zones across the project area.

[redacted]

Figure 1-26 – [redacted]

[redacted]

Figure 1-27 – [redacted]

[redacted]

Figure 1-28 – [redacted]

1.5.2 Velocity Control and Synthetic Seismogram

The main input for the velocity model used in the depth conversion of the seismic was the 2007 seismic Pre-Stack Time Migration (PSTM) processing-derived velocity cube. These velocities were compared with the only available checkshot from a well located in the middle of the survey, the L B SIMONEAUX No. 002 (SN 186913), approximately 1.57 mi north of the proposed injection wells. This checkshot data is presented in Table 1-8. Down to about 12,000 ft TVD (below the Cris I shale, lower confinement), the seismic and checkshot velocities only vary on the order of +/- 1%. Over the depth range of the well, the seismic velocities were scaled to match the checkshot and synthetic in this well.

Well synthetics were generated for four other wells across the survey via calculating artificial density and velocity logs from the resistivity logs. These wells were chosen because they have a resistivity log over an extensive depth range and provide four additional data points, where the seismic velocity data and the velocity model could be scaled, tied, and quality-checked. The outline of the seismic velocity data was shown in Figure 1-24. In the same figure, the location of the well with the checkshot data is highlighted with a yellow diamond. The other four wells used to tie the velocity model are highlighted with white circles. These are C E GHEENS No. 060 (SN 109671), S J SIMONEAUX No. 001 (SN 33280), ST CHARLES PH SCHL BD 001 (SN 202777) and SIM 10 RA SUA;SIMONEAUX No. 017 (SN 142882). The checkshot velocity information and synthetic well tie from well L B SIMONEAUX No. 002 (SN 186913) is illustrated in Figure 1-29.

Table 1-8 – L B SIMONEAUX No. 002 (SN 186913) checkshot velocity data

No.	MD (ft)	TWT (ms)	Average Velocity (ft/s)	Interval Velocity (ft/s)
1	1	0	--	5,682
2	1,001	352	5,682	6,410
3	2,001	664	6,024	7,273
4	3,001	939	6,390	7,576
5	3,501	1,071	6,536	7,752
6	4,001	1,200	6,667	8,065
7	5,001	1,448	6,906	8,264
8	5,501	1,569	7,011	8,621
9	6,001	1,685	7,122	8,850
10	6,501	1,798	7,230	9,346
11	7,001	1,905	7,349	9,346
12	7,501	2,012	7,455	9,259
13	8,001	2,120	7,547	9,709
14	8,501	2,223	7,647	9,901
15	9,001	2,324	7,745	10,000
16	9,701	2,464	7,873	10,200
17	10,211	2,564	7,964	10,676
18	11,001	2,712	8,112	10,638
19	11,501	2,806	8,197	10,204
20	12,001	2,904	8,264	9,346
21	12,501	3,011	8,303	8,772
22	13,001	3,125	8,320	9,009
23	13,501	3,236	8,344	9,091
24	14,001	3,346	8,368	8,850
25	14,501	3,459	8,384	8,264
26	15,001	3,580	8,380	8,547
27	15,501	3,697	8,385	8,571
28	15,621	3,725	8,387	--

*TWT – two-way travel time
ms – milliseconds
ft/s – feet per second

[redacted]

Figure 1-29 – [redacted]

1.5.3 Formation Tops

Formation tops were correlated using all available well logs (SP, gamma ray (GR), resistivity—and neutron and density where available) and were guided by interpreted seismic horizons, shown in Figure 1-30. Formation top names were applied to interpreted horizons. Due to the large number of tops, number prefixes were added to the names to ensure data integrity. Regional shale beds, which are present throughout the model area and beyond, were identified and correlated across the available well logs and then tied to seismic reflection events (i.e., 28_MM1_2 and 30_MM2_1). Overall, 28 interpreted formation tops were used to characterize the subsurface in and beyond the project area.

[redacted]

Figure 1-30 – [redacted]

1.5.4 Structural Interpretation

The structural model incorporated 28 interpreted seismic time horizons, which were converted to depth and tied to the formation tops from 57 wells inside the areal extent of the model. Additionally, seven PaleoScan horizons were autotrack-generated through intervals where the reflectors exhibit discontinuous character; this occurs predominantly in the upper section due to highly localized channel-controlled proximal deposition. In total, the structural model incorporates 35 seismic horizons and 13 faults as shown in Figure 1-31. Five of these faults were identified and interpreted directly from seismic data. (Note: An additional four faults were seismically interpreted but exist outside of the model boundary.) Fault extents and additional faults outside the seismic survey were included in the geomodel based on Geomap and published regional maps. Figure 1-33 illustrates the geologic faults and horizons interpreted from input data.

[redacted]

Figure 1-31 – [redacted]

1.6 Geocellular Model

The geocellular model was designed to include the lease boundary and 3D seismic survey and was expanded to include the area where log data is available, to provide the comprehensive data set for the geomodel. The model area was expanded beyond the lease area to adequately model plume and critical pressure responses. The model covers approximately 99 sq mi (63,360 acres) and ranges from 1,859 ft to 11,771 ft in depth. The southern edge of the model, which is outside of the lease boundary, was limited by the fault zone interpreted from seismic and the Geomap fault database. Figure 1-32 summarizes the distribution of well log and seismic data as well as the extent of the 3D geocellular model, shown on the map as the area of interest (AOI). Of the 401 wells within the model boundary, 57 wells with logs were used for property modeling—out of which 37 wells are within the seismic survey and 20 wells are within the lease boundary. The 57 wells with formation tops were used jointly with seismic data to construct the structural framework of the model.

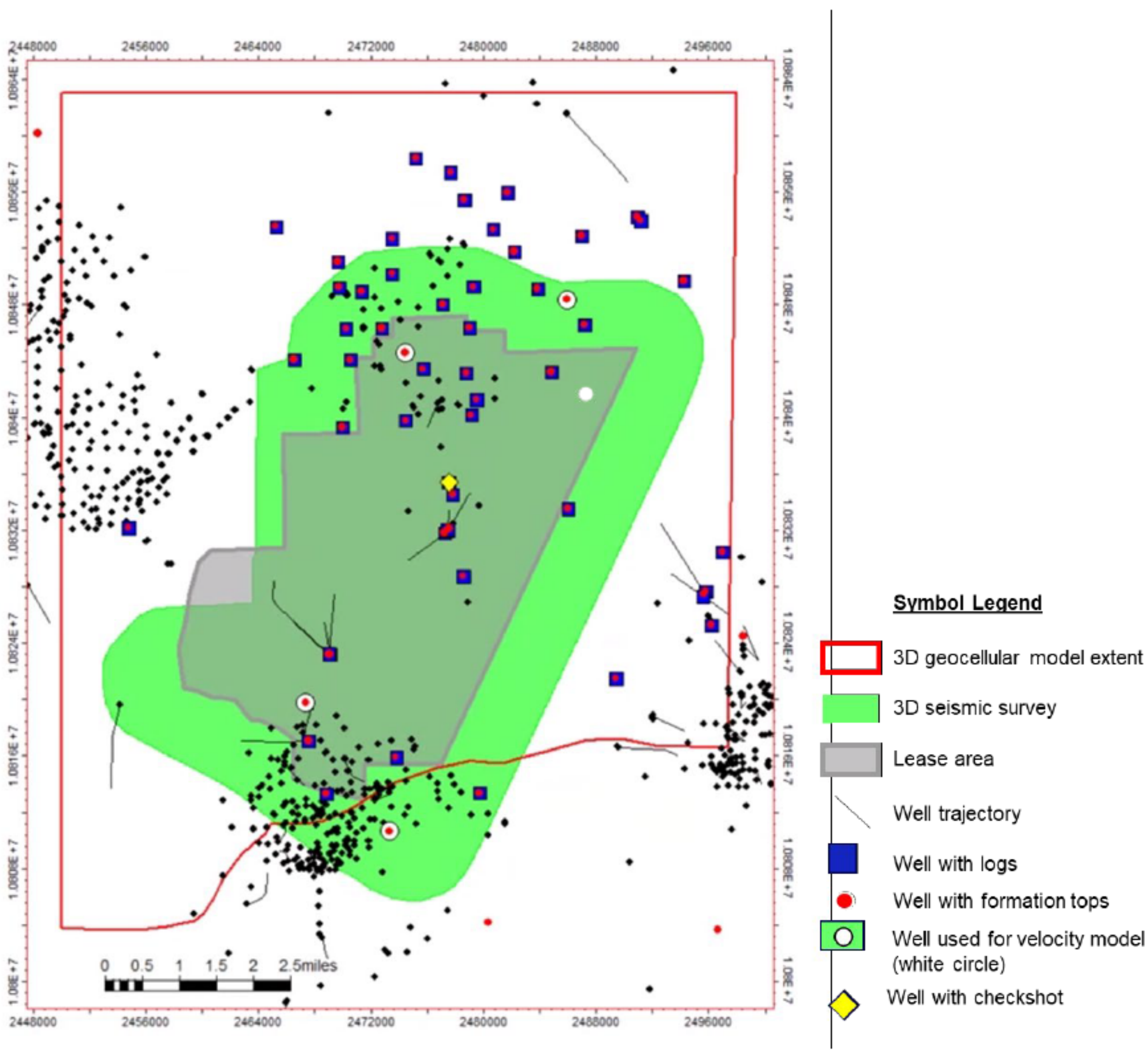

Figure 1-32 – Libra project area map, showing seismic and well data coverage, and the lease and geomodel boundaries.

Geocellular model construction includes the following two major steps:

- Building the structural framework and creating the 3D geocellular grid
- Distributing petrophysical rock types and petrophysical properties to every cell in the model

Petrel™ E&P Software (Ver. 2023.4.0) from SLB (formerly Schlumberger) was used to generate the geocellular model for the Libra project. This software was chosen for its seamless integration from seismic/well log interpretation to geocellular modeling to reservoir simulation, enabling accurate modeling of the reservoir and confining systems. The geocellular model is also referred to as a static model, grid, model, or fine-scale geocellular model (FSGM) throughout this report.

1.6.1 Structural Framework

The geocellular structural framework was built based on the interpretation of seismic horizons and formation tops. The 28 initial seismic time horizons were interpreted, converted to depth, and tied to the formation tops from 57 wells inside the areal extent of the model. Additionally, seven PaleoScan horizons, which were initially autotrack-derived without formation tops, were proportionally adjusted using thickness maps to prevent crossover of the surfaces. In total, the geocellular structural framework incorporates 35 seismic horizons and 13 faults, 5 of which were interpreted from seismic data. Additional faults outside the seismic survey were included in the geomodel based on Geomap and published regional maps.

Petrel software requires that faults included in the grid must extend from the top to the base of the model, even if the faults do not geologically exist through the entire model interval. To counteract the software limitation of artificial fault extension and existence, the modeled faults can be inactivated within defined zone intervals, thereby making the fault effectively nonexistent during horizon modeling. The 3D fault model included 13 faults, which were extended to the top and base of the grid, honoring the structural dip of the faults. Seven faults (FN7_GM, FN2_3dGM, FN3_3dGM, FN4_GM, FN5_GM, FN6_GM, and FN1_3dGM) in the north were inactivated from Zone 01_Top_Grid through Zone 30_MM2. When sampling the faults from the fault model into the 3D grid, the faults were orthogonalized. Figure 1-33 displays the fault model and the faults in the grid.

[redacted]

Figure 1-33 – [redacted]

Table 1-9 summarizes the model horizons and sources used to generate them, and a 3D view of the geocellular structural model is shown in Figure 1-34(b).

Table 1-9 – Summary of the model horizons and source(s) used to generate them.

Horizon No.	Horizon Name	Well Tops Used	Seismic Horizon Used
1	Top_Grid	yes	yes
2	Top of UCZ	yes	yes
3	Base of UCZ (Rob E)	yes	yes
4	35140	no	yes (PaleoScan)
5	3218	no	yes (PaleoScan)
6	UM1_1	yes	yes
7	UM1_2	yes	yes
8	UM1_Base	yes	yes
9	3010	no	yes (PaleoScan)
10	*Cristellaria K*	yes	yes
11	UM2_1	yes	yes
12	2812	no	yes (PaleoScan)
13	2760	no	yes (PaleoScan)
14	2728	no	yes (PaleoScan)
15	UM2_2	yes	yes
16	UM2_Base	yes	yes
17	UM3_1	yes	yes
18	UM3_2	yes	yes
19	*Bigenerina Nodosaria*	yes	yes
20	UM3_4	yes	yes
21	UM3_5	yes	yes
22	UM3_6	yes	yes
23	UM3_7	yes	yes
24	UM3_Base	yes	yes
25	UM4	yes	yes
26	Top of Middle Miocene	yes	yes
27	MM1_1	yes	yes
28	MM1_2	yes	yes
29	MM1_Base	no	yes
30	MM2_1	yes	yes
31	MM2_Base	yes	yes
32	1892	no	yes (PaleoScan)
33	Top of LCZ (Cristellaria I)	yes	yes
34	Base of LCZ	yes	yes
35	Bottom_Grid	yes	yes

Initial Structural Model **Resultant Geocellular Structural Framework**

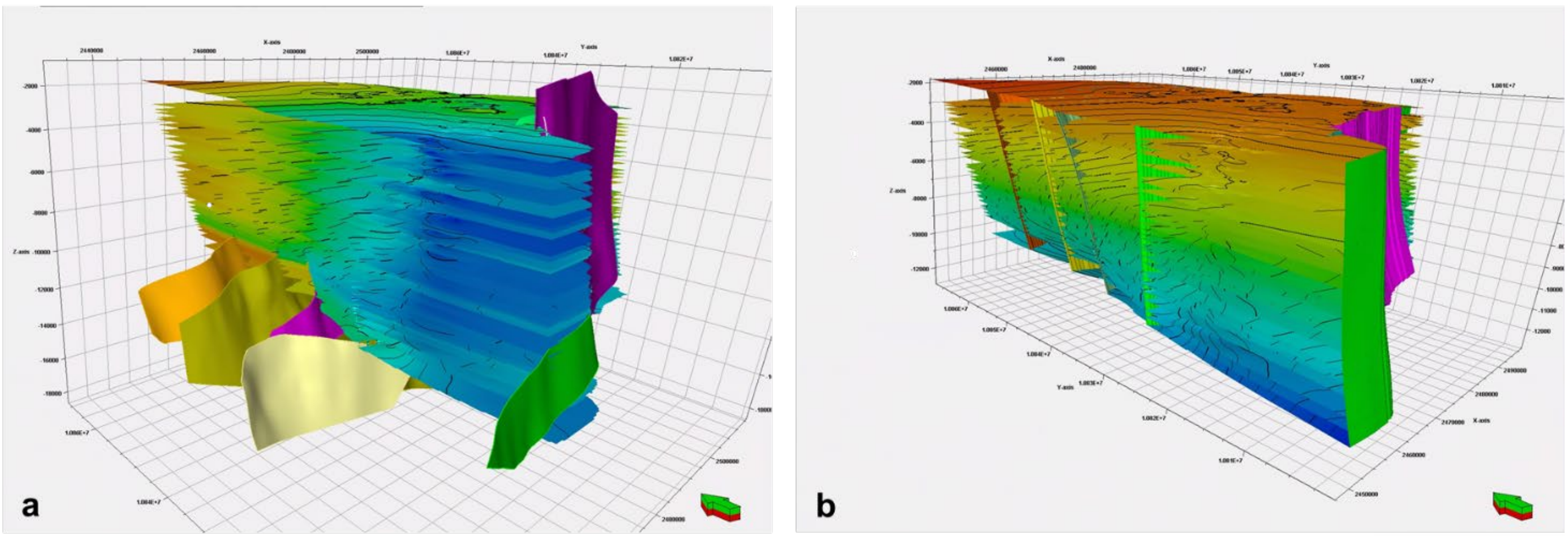

Figure 1-34 – (A) 3D view of the initial structural model generated from seismic interpretation and formation well tops. (B) 3D view of the geocellular structural framework, consisting of a fault model and horizons, generated from the initial structural model. All faults in the geocellular model have been extended to the top and base of the model as required by Petrel. Northern faults observed in 3D seismic terminate at Zone_30_MM2_1 and are deactivated in the horizons modeling process from Zone 1.

Using this structural model, the 3D grid was created with horizontal cell dimensions of 200 ft x 200 ft. Vertically, a proportional layering method was applied, leading to the vertical cell dimensions with an average of 5 ft for the main intervals of interest within the injection zone. The heterogeneity of the well logs is adequately captured with this cell thickness scheme. Cells are rotated at zero degrees. Table 1-10 provides a summary of the model zones and their gridding parameters. The number of grid cells in the constructed model totaled 92,879,472 with 78,816,586 active cells.

Table 1-10 – Summary of the model zones and their gridding parameters. Confining zones are highlighted in gray, and the injection zone is highlighted in orange.

Zone Name	Top Horizon	Base Horizon	No. of Layers	Mean Cell Thickness (ft)
01_Top_Grid	Top_Grid	Top of UCZ	25	24
02_UCZ	Top of UCZ	Base of UCZ (Rob E)	30	9
03_Top_Miocene	Base of UCZ (Rob E)	3514	25	6
04__3514	3514	3218	25	8
05__3218	3218	UM1_1	25	5
06_UM1_1	UM1_1	UM1_2	55	5
07_UM1_2	UM1_2	UM1_Base	55	5
08_UM1_Base	UM1_Base	3010	40	4
09__3010	3010	*Cristellaria K*	40	6
10_Cristell_K	*Cristellaria K*	UM2_1	75	5
11_UM2_1	UM2_1	2812	50	5
12__2812	2812	2760	45	5
13__2760	2760	2728	15	10
14__2728	2728	UM2_2	45	6
15_UM2_2	UM2_2	UM2_Base	75	4
16_UM2_Base	UM2_Base	UM3_1	70	4
17_UM3_1	UM3_1	UM3_2	50	4
18_UM3_2	UM3_2	*Bigenerina Nodosaria*	65	2
19_Big_Nod	*Bigenerina Nodosaria*	UM3_4	35	6
20_UM3_4	UM3_4	UM3_5	25	6
21_UM3_5	UM3_5	UM3_6	20	5
22_UM3_6	UM3_6	UM3_7	40	5
23_UM3_7	UM3_7	UM3_Base	45	6
24_UM3_Base	UM3_Base	UM4	60	5
25_UM4	UM4	Top of Middle Miocene	30	6
26_MidMio	Top of Middle Miocene	MM1_1	25	11
27_MM1_1	MM1_1	MM1_2	20	8
28_MM1_2	MM1_2	MM1_Base	1	31
29_MM1_Base	MM1_Base	MM2_1	30	5
30_MM2_1	MM2_1	MM2_Base	1	138
31_MM2_Base	MM2_Base	1892	20	11
32__1892	1892	Top of LCZ (Cris I)	50	6
33_LCZ	Top of LCZ (Cris I)	Base of LCZ	50	6
34_Bottom_Grid	Base of LCZ	Bottom_Grid	40	15
Total Layers			1,302	

1.6.2 Rock Properties Modeling

Property modeling is a process whereby grid cells are populated with discrete or continuous values, with the goal of using all available geological information to build a realistic representation of the subsurface rock properties. Well log data, seismic data, and interpreted geostatistical parameters guide the inter-well distribution of rock properties such as PHIE and permeability in the geocellular grid. The following properties were 3D modeled, using Petrel, to represent the subsurface: seismic regions, PRT, PHIE, permeability, net-to-gross (NTG). The resultant petrophysical properties were used for dynamic simulation of the critical pressure front and CO_2 plumes.

This section will cover the analysis and population of reservoir properties, validation methods, and quality control of the geocellular model output. The following topics are discussed:

- Seismic regions property generation using sand-prone and shale-prone polygons interpreted from zonal seismic attributes and well logs
- Scale-up well logs into grid including PRT, PHIE, and permeability
- Data analysis including variogram, vertical proportion curves, distributions, and data transformations
- PRT modeling of PRT-1 (sand + silt), and PRT-0 (shale) (proportions of PRTs conditioned to each seismic region)
- PHIE modeling within the PRT-1 (sand + silt)
- Permeability modeling within PRT-1, using Gaussian random function simulation algorithm, collocated and co-krigged to the PHIE property
- NTG estimation using PHIE cutoffs

1.6.2.1 Seismic Regions Property Definition

Seismic data may be related to rock properties and used to guide the inter-well distribution of PRTs. An analysis was performed to discern whether a relationship existed between the PRT well logs and the 3D seismic data. A relationship was observed between the elastic impedance sum of positive amplitudes (SPA) zonal extractions and zonal PRT well-log statistics. This observed relationship was used to predict general areal lithofacies distributions (sand-prone and shale-prone aerial regions). Seismically interpreted polygons, based from zonal seismic SPA attribute response in combination with PRT well-log control, were created for each zone in the grid to delineate sand-prone and shale-prone aerial regions. The regions were used in PRT property modeling to distribute different proportions of PRTs in each aerial region (e.g., shale-prone regions have a higher proportion of PRT-0 (shale) to PRT-1 (sands/silts) distributed within the region).

Data Analysis of Zonal Seismic Attributes

The Miocene depositional environment in which the proposed IZ sedimentation took place was that of a distal-to-proximal deltaic setting, with older sediments being more distal and younger sediments more proximal. The main sediment source was the ancestral Mississippi and Tennessee Rivers.

To predict clastic lithofacies with seismic data, the distribution of several seismic attributes was calculated for the zones in the geomodel (intervals between the horizons). An elastic inversion (e.g., Connolly, 1999; Cambois, 2000; Zhou and Hilterman, 2007) was applied to the far- and near-stacks and were then combined and linearly weighted to achieve the best fit to the SP logs, as displayed in Figure 1-35.

The elastic-inversion seismic lithofacies were compared to the PRT well logs. The PRT well log consisting of two PRTs was interpreted based on the Vsh percent ranges as PRT-1 (Vsh of 0–70%: sand + silt) and PRT-0 (Vsh >70%: shale).

When comparing the resulting elastic impedance SPA zonal extractions to zonal PRT well-log statistics, the SPA zonal extractions correlated excellently to the zonal well-log statistics and can be used to predict general areal lithofacies distributions. It was observed that the greater the magnitude, the positive amplitudes then correlated to areas where the well logs showed a high percentage of sand, and are interpreted as sand-prone regions. Conversely, lower amplitudes corresponded to areas where well logs showing a predominantly higher percent of shale are interpreted as shale-prone regions. The relationship between zonal PRT well-log statistics and the SPA zonal extractions is illustrated in Figure 1-36.

Polygons were created for each zone to delineate sand-prone and shale-prone areas based on zonal SPA response in combination with well-log control. The polygons were expanded beyond the seismic survey to the model boundary via log interpretation, as shown in Figure 1-37. The polygons were used to generate a seismic region 3D property to be used in PRT property modeling, to guide the areal extent and proportion of PRTs distributed within the model.

[redacted]

Figure 1-35 – [redacted]

[redacted]

Figure 1-36 – [redacted]

[redacted]

Figure 1-37 – [redacted]

Regions Definition

The seismic regions property is used in PRT modeling as a hierarchical biasing property where different proportions of PRTs are distributed within each seismic region. The seismic regions property was defined deterministically; for each zone, the seismic interpreted polygons were directly sampled into the grid, generating the discrete property composed of two codes—SR-0 and SR-1 representing shale-prone and sand-prone regions, respectively. An example of the relationship between the zonal SPA map, seismic polygons, and the resultant seismic regions property are shown in Figure 1-38 for Zone 10_Cristell_K.

[redacted]

Figure 1-38 – [redacted]

1.6.2.2 PRTs Modeling

For dynamic simulation of the CO_2 plume and critical pressure front, PHIE and permeability properties are required. Each PRT has unique petrophysical distributions of PHIE and permeability. Although a PRT property is not required for dynamic simulation, it is modeled so that petrophysical rock properties of the strata can be more realistically represented in the model.

The PRT modeling is a multi-step process. First, the discrete PRT well logs are sampled into the grid through an operation known as well log upscaling. Next, data analyses are performed using well log and seismic data to interrogate the data and estimate geostatistical parameters needed for the modeling algorithm. Finally, the PRTs (PRT-0 and PRT-1) are biased to the seismic regions property, meaning that different proportions of each PRT as well as geostatistical parameters (e.g., vertical proportion curves and variogram settings) were defined for each seismic region code—and 3D distributed into every cell of the model guided by the sequential indicator simulation (SIS) modeling algorithm.

Scale-Up PRT Well Logs

The PRT well log was interpreted in the model AOI for 57 wells with SP-derived Vsh and effective porosity (PHIE) logs calibrated with available density/neutron logs. As noted earlier, two PRTs were interpreted based on the Vsh percent ranges as PRT-1 (Vsh of 0–70%: sands and silts) and PRT-0 (Vsh >70%: shale).

The PRT well log was upscaled into the grid using the "most of" method, meaning the dominant PRT log value in each cell is assigned. Figure 1-39 shows an example of the PRT well-log interpretation and the scaled-up PRT log along a five-well correlation section. The well log and resulting upscaled log are very similar, indicating that the heterogeneity of the log was captured during the upscaling process and that the model cell thickness is appropriate. Figure 1-40 displays histograms of well logs and upscaled logs for the PRT, PHIE, and permeability properties in Zone 10_Cristell_K. The histograms show that the raw well-log heterogeneity was adequately captured by the upscaled logs.

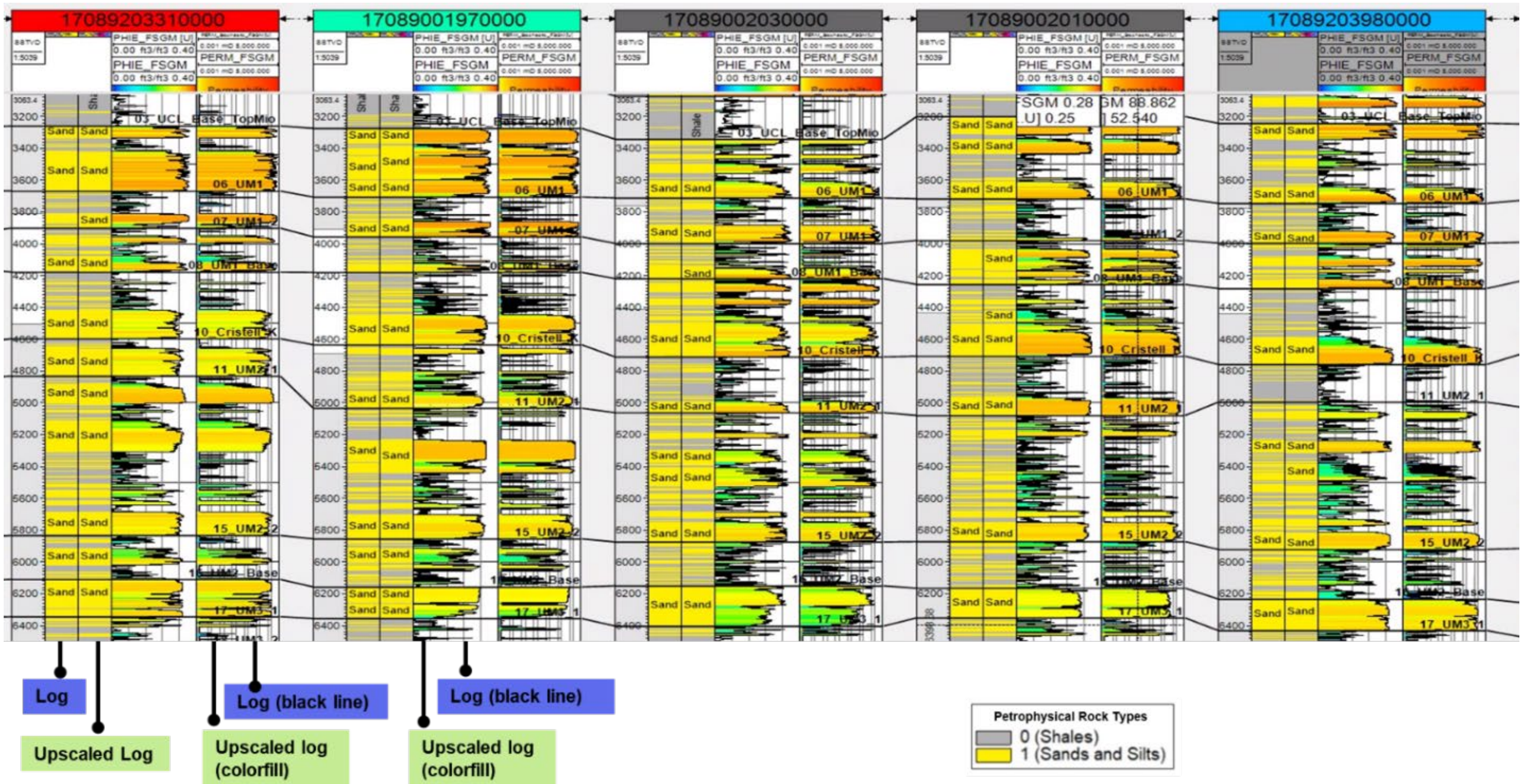

Figure 1-39 – Example of PRT interpretation based on Vsh in a 5-well correlation section, with horizons "5 (3218)" to "17 (UM3_1)" displayed.

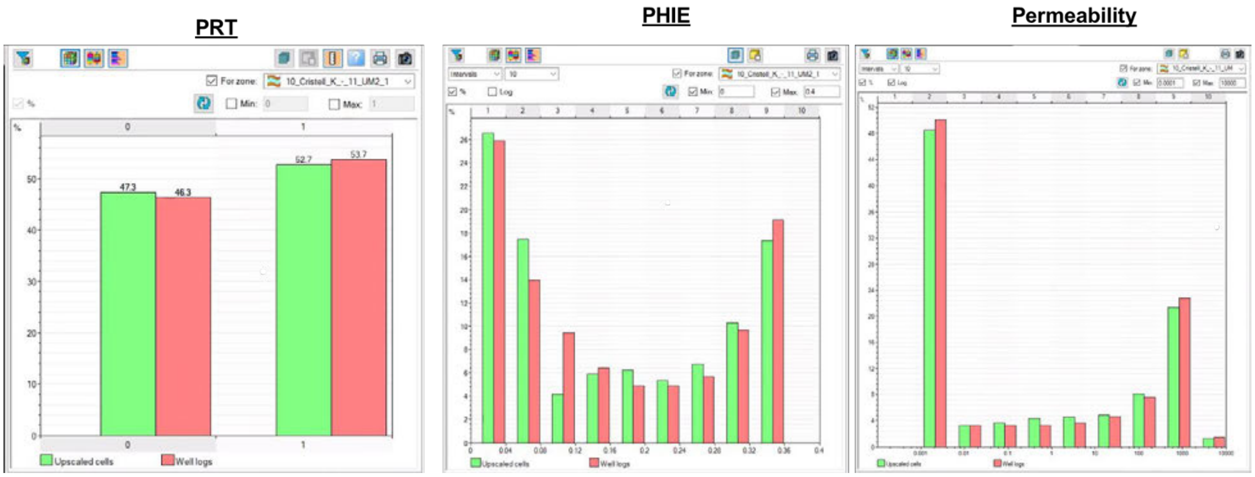

Figure 1-40 – PRT, PHIE, and permeability comparison histograms of well logs and upscaled logs used for Zone_10_Cristell_K. The upscaled well logs (green) are very similar to the raw well logs (red) indicating that the geologic heterogeneity has been captured and the current layering scheme is representative.

Data Analyses for PRTs

Data analyses were performed using the PRT well log, upscaled log, and seismic data to determine the geostatistical parameters that are used by the modeling algorithm to guide the 3D inter-well distribution of values during property modeling. For PRT modeling, the calculated geostatistical parameters include the variogram and the vertical proportion curves calculated for each seismic region and model zone.

Variogram Model Definition

Variograms were estimated for each seismic region (SR-0 = shale-prone, SR-1 = sand-prone) and each zone in the grid. The required geostatistical variogram inputs for Petrel include the following: horizontal major and minor range, vertical range, nugget, sill, type, and major azimuthal direction. The major azimuthal direction in the variogram model can be defined as one directional value for an entire zone. Alternatively, the major azimuthal direction can vary from cell to cell in the grid and is referred to as a locally varying azimuth. Variogram parameters were estimated using Petrel.

Horizontal variograms were estimated using geologic concepts, well log, and seismic data. Horizontal variograms have a larger connectivity in sand-prone regions, which increases with depth. Table 1-11 summarizes variogram parameters for each of the model zones. Vertical variograms were calculated for each seismic region in each zone using well logs. For the vertical range, the number of lags and search distance were set so that the lag distance was approximately equal to the sampling interval of the logs. An example of a vertical variogram over a defined zone is shown in Figure 1-41. For each seismic region and zone, a nugget value of 0.0001, a sill value of 0.9999, and an exponential variogram type were defined.

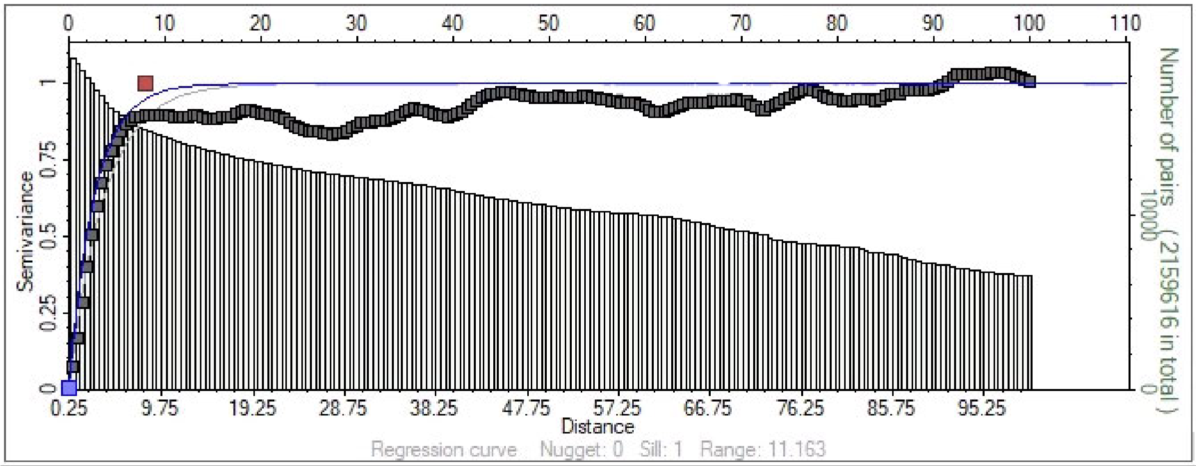

Figure 1-41 – Example of vertical variogram estimated from PHIE well log data for Zone_10_Cristell_K for PRT-0 (shale). The exponential variogram type best fits the data.

Table 1-11 – Variogram Parameters and PRTs for the Model Zones

	Sand-Prone Region			Shale-Prone Region			
	Horizontal			Horizontal			
	Major	Minor	Vertical	Major	Minor	Vertical	
Zone	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	Comments
01_Top_Grid	3500	1500	27	2000	1000	20	
02_UCZ	3500	1500	20	2000	1000	15	
03_Top_Miocene	3500	1500	12	2000	1000	10	
04__3514	3500	1500	18	2000	1000	7	
05__3218	3500	1500	12	2000	1000	10	
06_UM1_1	3500	1500	14	2000	1000	11	
07_UM1_2	3500	1500	13	2000	1000	13	
08_UM1_Base	4000	2000	12	2000	1000	13	
09__3010	4000	2000	12	2000	1000	13	
10_Cristell_K	4000	2000	14	2000	1000	14	
11_UM2_1	4000	2000	12	2000	1000	13	
12__2812	4000	2000	13	2000	1000	10	
13__2760	4000	2000	16	2000	1000	15	
14__2728	4000	2000	14	2000	1000	11	
15_UM2_2	4000	2000	9	2000	1000	12	
16_UM2_Base	4000	2000	12				(no shale prone region)
17_UM3_1	5000	2000	11	2500	1000	11	
18_UM3_2	5000	2000	8				(no shale prone region)
19_Big_Nod	5000	2000	10	2500	1000	7	
20_UM3_4	5000	2000	15	2500	1000	9	
21_UM3_5	5000	2000	12	2500	1000	14	
22_UM3_6	5000	2000	10	2500	1000	11	
23_UM3_7	6000	2500	15	3000	1500	12	
24_UM3_Base	6000	2500	9				(no shale prone region)
25_UM4	6000	2500	14	3000	1500	12	
26_MidMio	6000	2500	24				(no shale prone region)
27_MM1_1	6000	2500	20	3000	1500	21	
28_MM1_2							Regional shale
29_MM1_Base	6000	2500	13	3000	1500	7	
30_MM2_1							Regional shale
31_MM2_Base	6000	2500	15	3000	1500	25	
32__1892	6000	2500	15	3000	1500	20	
33_LCZ	6000	2500	15	3000	1500	15	
34_Bottom_Grid	6000	2500	20	3000	1500	25	

Locally varying azimuth (LVA) maps were interpreted and generated for each zone. The interpretation was guided by the seismic SPA attribute maps, seismic region polygons, and PRT well logs. The LVA maps are used to guide the aerial connectivity of property values in PRT, PHIE, and permeability modeling. An LVA map indicates that each aerial cell may have a different azimuthal value assigned. Figure 1-42 schematically illustrates how the LVA maps guide the PRTs' property aerial distribution within the model.

[redacted]

Figure 1-42 – [redacted]

Vertical Proportion Curves

Vertical proportion curves (VPCs) were incorporated into PRT analysis and modeling. The PRT VPCs were estimated within each of the seismic regions, and each grid zone based on the upscaled well logs. Vertical proportion curves are used in modeling to guide the proportion of PRT-1 and PRT-0 that are distributed within each seismic region (SR-1 = sand prone, and SR-0 = shale prone) and k-layer of the model. Proportions were matched to the upscaled PRT well log in each k-layer. Figure 1-43 illustrates defined VPCs for the SR-0 and SR-1 seismic regions for Zone_10_Cristell_K, and their relationship with PRTs defined by seismic attributes.

With VPCs, the vertical heterogeneity of the model zone and seismic region is captured by distributing the PRT based on upscaled log response within each k-layer and seismic region. Without VPCs, Petrel assigns the total upscaled percentages of each PRT to each k-layer within the model instead of individual percentages to each k-layer. The VPCs were used as a vertical trend in property modeling.

3D Distribution of PRTs

Once the well logs were upscaled and geostatistical parameters estimated, the 3D inter-well distribution of PRTs could be performed. The PRT property was stochastically modeled using the SIS algorithm, upscaled logs, seismic regions, and geostatistical parameters.

The distribution of PRTs was biased to the seismic regions property, meaning that for each seismic region (i.e., shale-prone region, sand-prone region) and each zone, different proportions of PRT-0 and PRT-1, variogram parameters, and vertical proportion curves were defined.

The total 3D distribution of PRTs was assigned from the upscaled PRT well-log proportions observed in each seismic region and zone. Figure 1-43 visually illustrates in one k-layer of the PRT property how different proportions of PRT-0 and PRT-1 are assigned within each of the seismic regions. Histograms of the well logs, upscaled logs, and resultant 3D property distributions for Zone 10 by seismic region are shown in Figure 1-44.

[redacted]

Figure 1-43 – [redacted]

[redacted]

Figure 1-44 – [redacted]

The resultant 3D PRT property is shown in Figure 1-45. Figure 1-46 shows a PRT distribution histogram indicating that log values were accurately preserved during the upscaling and model construction.

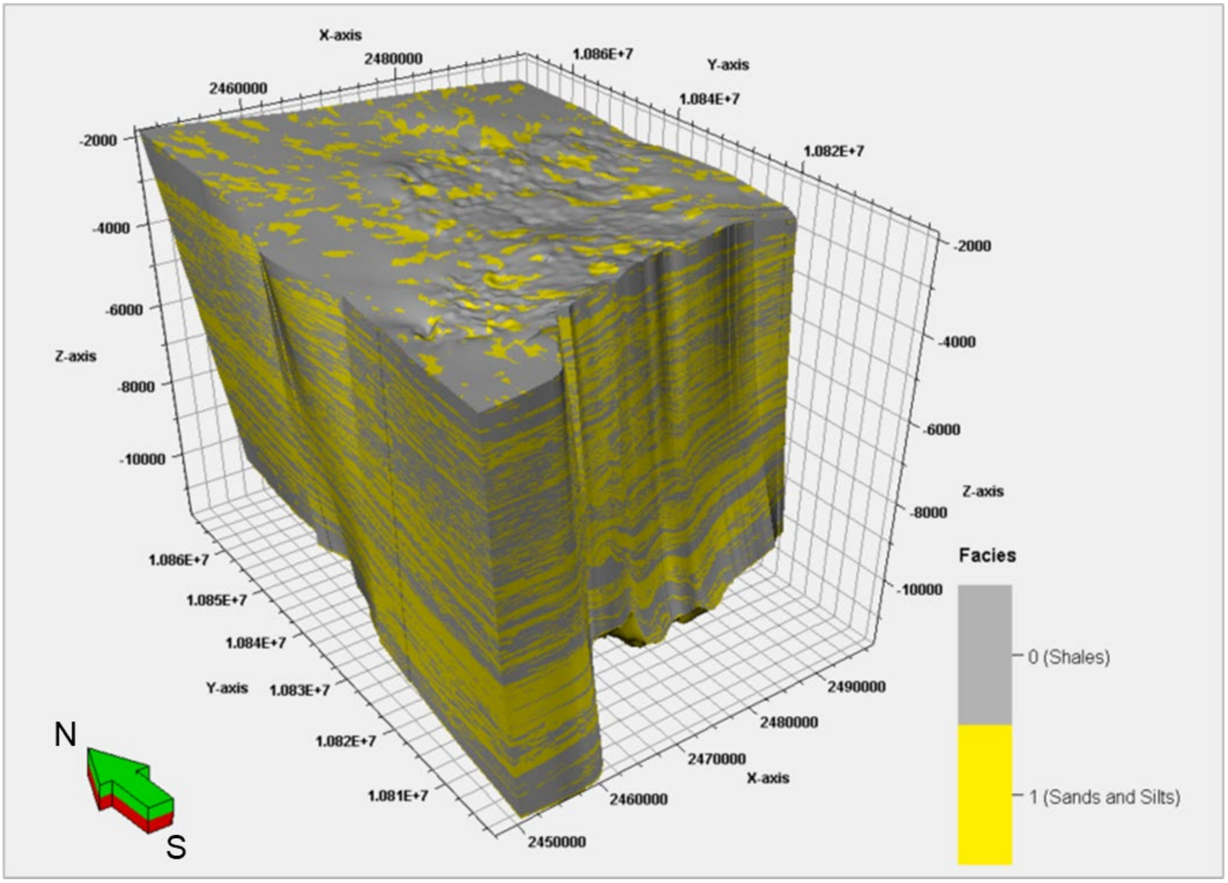

Figure 1-45 – Resultant 3D PRT Property in the 3D Model

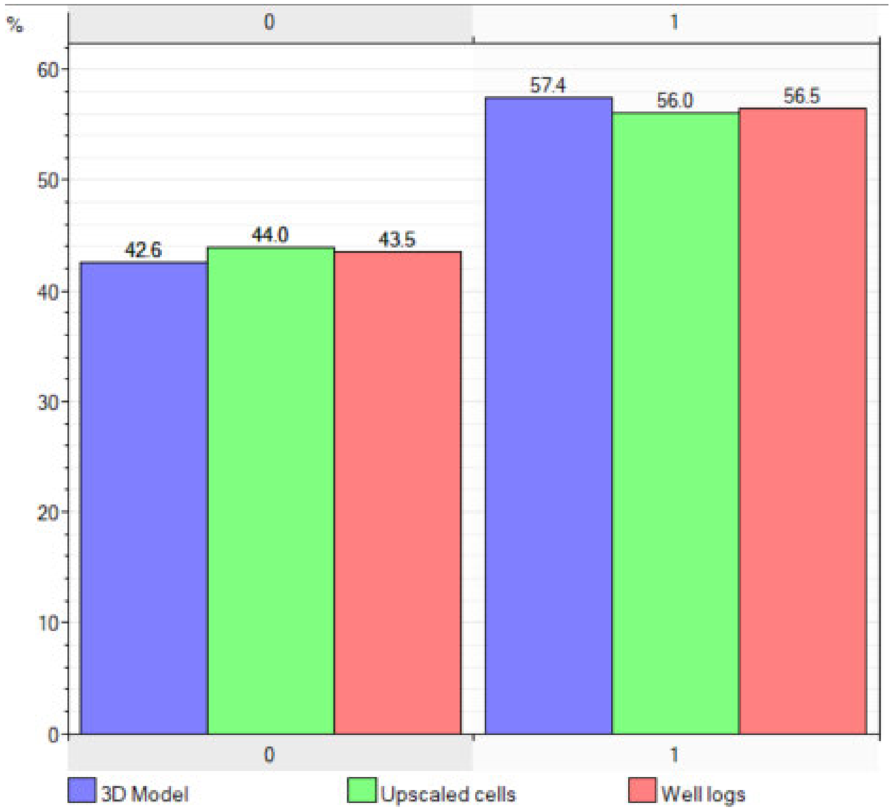

Figure 1-46 – Histogram Comparing PRTs from Raw Logs, Upscaled Logs, and 3D Property Model

1.6.2.3 Porosity Modeling

The PHIE values were distributed into every cell of the model guided by the modeling algorithms (i.e., Gaussian Random Function Simulation (GRFS), Assign Values), upscaled well logs, variogram model, and defined porosity distributions for PRT-1. A value of 0.0 was assigned to PRT-0 as it is considered to be shale and act as a flow barrier.

Scale-Up PHIE Well Logs

Porosity logs were derived during the petrophysical analysis and are discussed in *Section 1.4.3*, on petrophysics. The PHIE well log was used for 3D porosity modeling—arithmetically sampled into the grid using the PRT property as a biasing constraint. That is, if a cell had previously been assigned to a certain PRT, only those PHIE values in the well log associated with that specific PRT would be used in estimating the upscaled average value of the PHIE for that cell. The upscaled porosity-log data values were checked for accuracy against the raw log data by comparing them in the well section and histograms (Figures 1-39 and 1-40). For the PHIE property, the upscaling resulted in a good match with the raw log data, indicating that the PHIE log heterogeneity was effectively captured in the upscaling.

Data Analysis for Effective Porosity

Data analyses were performed using the PRT and PHIE well logs, upscaled log, and seismic data, with the objective of estimating the required geostatistical parameters used by the modeling algorithm to guide the 3D inter-well distribution of PHIE values during property modeling. For PHIE modeling, the calculated geostatistical parameters include the variogram and statistical PHIE distributions within PRT-1 and for each model zone. Statistical analysis is not performed for PRT-0 as it is assigned a PHIE value of 0.0 throughout the grid.

PHIE Variogram Definition

Variograms for PHIE were estimated within PRT-1, and in each zone in the grid. The required geostatistical variogram inputs for Petrel included the following: horizontal major and minor range, vertical range, nugget, sill, type, and major azimuthal direction. Variogram parameters were estimated using Petrel.

Vertical variograms for PHIE were calculated within PRT-1, in each zone using well logs. For the vertical range, the number of lags and search distance were set so that the lag distance was approximately equal to the sampling interval of the logs. Within PRT-1 of each zone, a nugget value of 0.0001, a sill value of 0.9999, and an exponential variogram type were defined. The horizontal variograms used in PRT modeling for the sand-prone region and LVA maps were used for PHIE modeling within the PRT-1 code. Table 1-12 summarizes variogram parameters for PHIE within PRT-1 in each of the model zones. Variogram values are not defined for PRT-0 because it is not stochastically modeled, and is assigned a PHIE value of 0.0.

Table 1-12 – Variogram Parameters for PHIE and Permeability within PRT-1 in Each of the Model Zones

	PRT-1				
	Horizontal		PHIE	Permeability	
	Major	Minor	Vertical	Vertical	
Zones	(ft)	(ft)	(ft)	(ft)	Comments
01_Top_Grid	3,500	1,500	12	20	
02_UCZ	3,500	1,500	10	8	
03_Top_Miocene	3,500	1,500	20	20	
04__3514	3,500	1,500	13	6	
05__3218	3,500	1,500	14	10	
06_UM1_1	3,500	1,500	11	7	
07_UM1_2	3,500	1,500	13	7	
08_UM1_Base	4,000	2,000	6	5	
09__3010	4,000	2,000	15	6	
10_Cristell_K	4,000	2,000	13	5	
11_UM2_1	4,000	2,000	12	5	
12__2812	4,000	2,000	14	6	
13__2760	4,000	2,000	11	10	
14__2728	4,000	2,000	9	7	
15_UM2_2	4,000	2,000	6	5	
16_UM2_Base	4,000	2,000	17	20	
17_UM3_1	5,000	2,000	6	6	
18_UM3_2	5,000	2,000	23	12	
19_Big_Nod	5,000	2,000	10	5	
20_UM3_4	5,000	2,000	9	9	
21_UM3_5	5,000	2,000	12	10	
22_UM3_6	5,000	2,000	13	10	
23_UM3_7	6,000	2,500	7	6	
24_UM3_Base	6,000	2,500	16	8	
25_UM4	6,000	2,500	12	12	
26_MidMio	6,000	2,500	20	10	
27_MM1_1	6,000	2,500	8	9	
28_MM1_2					Entire zone is PRT-0
29_MM1_Base	6,000	2,500	20	13	
30_MM2_1					Entire zone is PRT-0
31_MM2_Base	6,000	2,500	18	11	
32__1892	6,000	2,500	12	9	
33_LCZ	6,000	2,500	7	7	
34_Bottom_Grid	6,000	2,500	12	10	

PHIE Data Transformations

Capturing the statistical distribution of PHIE values within cells assigned to PRT-1, in each zone, is a key component to data analysis. Upscaled well-log data within the model boundary were used to guide the minimum, maximum, mean, and standard deviation values within PRT-1 by zone. These statistical distributions are later applied during the 3D property modeling process as data transformations. A normal score data transform was applied to normalize and fit the PHIE data to a Gaussian distribution and prepare it for the modeling. This was performed on the upscaled log data and the results subsequently used in the GRFS.

3D PHIE Distribution

The objective of effective porosity modeling was to 3D populate the inter-well cells with PHIE values. For dynamic simulation, PHIE is a required property. Stochastically modeled PHIE values were conditioned to the previously modeled PRT property.

For cells assigned to PRT-0—considered to be shale and act as a flow barrier—all PHIE values were assigned a value of 0.0, including upscaled cells.

Within cells assigned to PRT-1, the PHIE values were stochastically distributed within the grid using the GRFS algorithm—guided by the upscaled PHIE well logs, variogram parameters including LVA maps (the same used for PRT modeling), and defined porosity distributions and data transformations for PRT-1. Figure 1-47(a) shows the resultant 3D PHIE property. Figure 1-48 shows the histogram for the well log, upscaled log, and 3D PHIE property within all zones for both PRTs. Figure 1-49 shows the histogram for the well log, upscaled log, and 3D PHIE property within Zone 10_Cristell_K for PRT-1 only. The 3D PHIE values within PRT-1 have a distribution similar to the upscaled log values.

After the model was populated with PHIE, the resultant property was (1) quality-checked by comparing the histogram distribution PHIE within PRT-1 for each zone, and (2) compared to the well log and upscaled well logs. The histograms show a good match to the well log data.

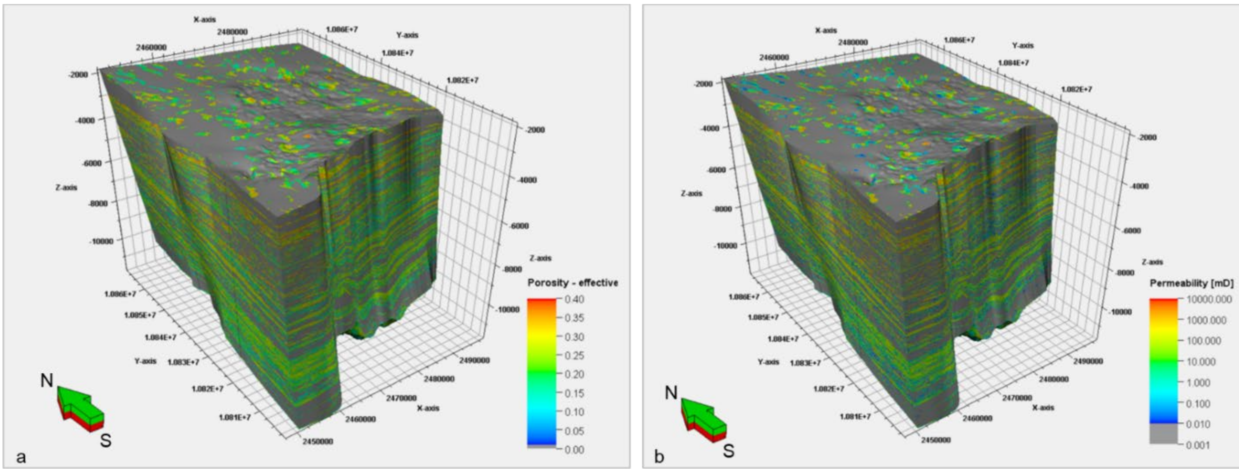

Figure 1-47 – 3D models of (a) effective porosity distribution and (b) permeability distribution.

1.6.2.4 Permeability Modeling

Permeability values were distributed into every cell of the model guided by modeling algorithms (i.e., GRFS, Assign Values), upscaled permeability well logs, variogram parameters, permeability distributions, data transforms, and the PHIE property within PRT-1. A value of 0.001 mD was assigned to cells previously assigned to PRT-0 (considered to be shale and act as a flow barrier).

Scale-Up Permeability Well Logs

As discussed in *Section 1.4.4* on petrophysics, the permeability well log was generated using a porosity-permeability equation that was derived using available core data, which were extracted for up to a 10,000 ft depth within a 50-mi radius of the model area from the BEG's GOMRQ. The sidewall core data from SL 7323 No. 001 (SN 159950), located 22 mi northeast of the model area, was also included.

Equation 4 shows the relationship for the permeability (in mD) well log as a function of porosity (%):

(Eq. 4) $$k = 1e\text{-}16 \times 10^{7}\ \phi^{12.436}$$

The permeability well log was used for 3D permeability modeling—geometrically sampled into the grid using the PRT property as a biasing constraint. That is, if a cell had previously been assigned to a certain PRT, only those permeability values in the well log associated with that specific PRT would be used in estimating the upscaled average value of the permeability for that cell. The upscaled permeability-log data values were checked for accuracy against the raw log data by comparing them in the well section and histograms (Figures 1-39 and 1-40). For the permeability property, the log upscaling resulted in a good match with the raw log data, indicating that the permeability log heterogeneity was effectively captured in the upscaling.

Data Analysis for Permeability

Data analyses were performed using the PRT and permeability well logs and the upscaled log, with the objective of estimating the required geostatistical parameters used by the modeling algorithm to guide the 3D inter-well distribution of permeability values during property modeling. For permeability modeling, the calculated geostatistical parameters included the variogram and the statistical permeability distributions within PRT-1 and for each model zone. Statistical analysis is not performed for permeability values within PRT-0 as it is assigned a permeability value of 0.001 mD throughout the grid.

Permeability Variogram Definition

Variograms for permeability were estimated within PRT-1, and in each zone in the grid. The required geostatistical variogram inputs for Petrel include the following: horizontal major and minor range, vertical range, nugget, sill, type, and major azimuthal direction. Variogram parameters were estimated using Petrel.

Vertical variograms for permeability were calculated within PRT-1, in each zone using well logs. For the vertical range, the number of lags and search distance were set so that the lag distance was approximately equal to the sampling interval of the logs. Within PRT-1 and each zone, a nugget value of 0.0001, a sill value of 0.9999, and an exponential variogram type were defined. The horizontal variograms used in PRT modeling for the sand-prone region and LVA maps were used for permeability within PRT-1. Table 1-12 summarized variogram parameters for permeability within PRT-1 in each of the model zones.

Permeability Data Transformations

Capturing the statistical distribution of permeability values within PRT-1 is a component to data analysis. For each zone, and within PRT-1 assigned cells, upscaled permeability well-log data were used to guide the minimum, maximum, mean, and standard deviation permeability values within PRT-1. These statistical distributions are later applied during the 3D property modeling process as data transformations. A logarithmic and normal score data transform were applied to normalize and fit the permeability data to a Gaussian distribution and prepare it for the modeling. These operations were performed on the upscaled log data and the results subsequently used in the GRFS.

3D Permeability Distribution

The objective of permeability modeling was to 3D populate the inter-well cells with permeability values. For dynamic simulation, permeability is a required property. Permeability was stochastically modeled, instead of equation generated, so as to add variability to the permeability values as observed with regional core data. The stochastically modeled permeability values were conditioned to the previously modeled PRT and PHIE properties.

Within cells assigned to PRT-1, permeability was stochastically modeled, guided by the upscaled permeability logs, variogram parameters, data distributions, and transformations. Permeability is modeled using the GRFS algorithm with collocated co-kriging, where the PHIE property is used as a secondary variable and an assigned correlation coefficient value of 0.985 for all modeled zones.

The PRT-0 (shale) permeability was assigned a value of 0.001 mD to all zones of the model. For PRT-1, permeability distributions were defined for each zone using the upscaled well log statistics. Figure 1-48 shows the resultant 3D permeability.

After the model was populated with permeability, the resultant property was (1) quality-checked by comparing the histogram distribution permeability within PRT-1 for each zone and (2) compared to the well log and upscaled well logs. The histograms show a good match to the well log data as shown on Figure 1-48 and 1-49. Additionally, a crossplot of effective porosity vs. permeability of the well logs, upscaled logs, 3D property, and regional core data is shown in Figure 1-50. The variability of the permeability property mimics that of the regional core data.

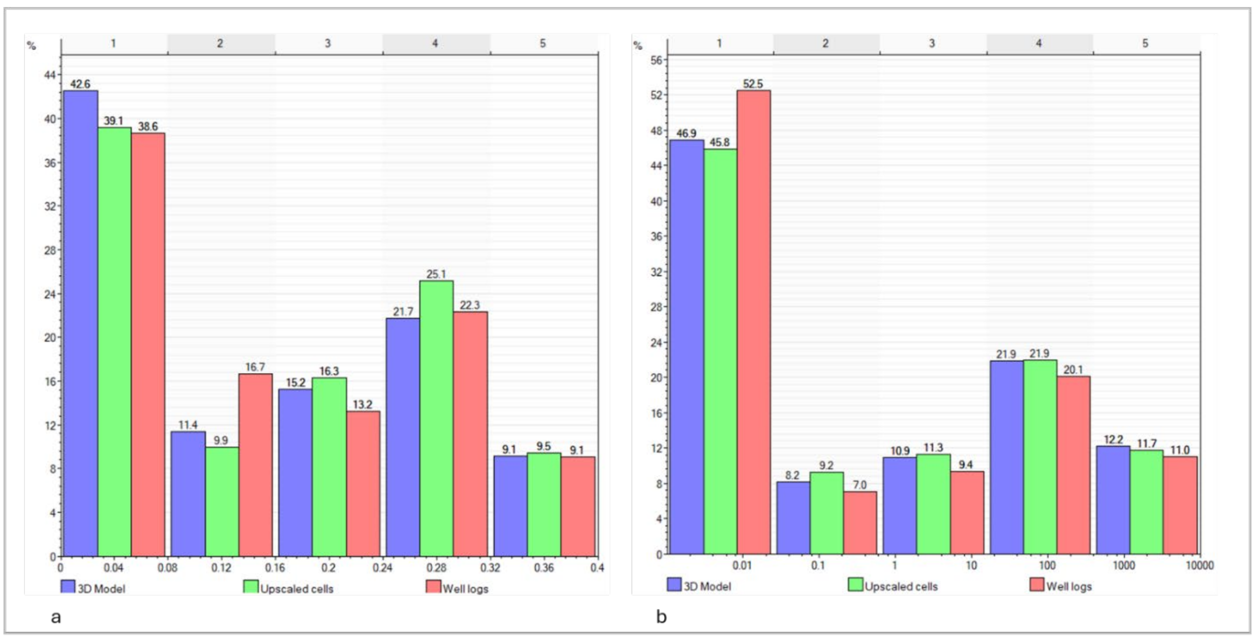

Figure 1-48 – Histograms comparing (a) porosity and (b) permeability from raw logs, upscaled logs, and the 3D property model for both PRT-0 and PRT-1, across all zones.

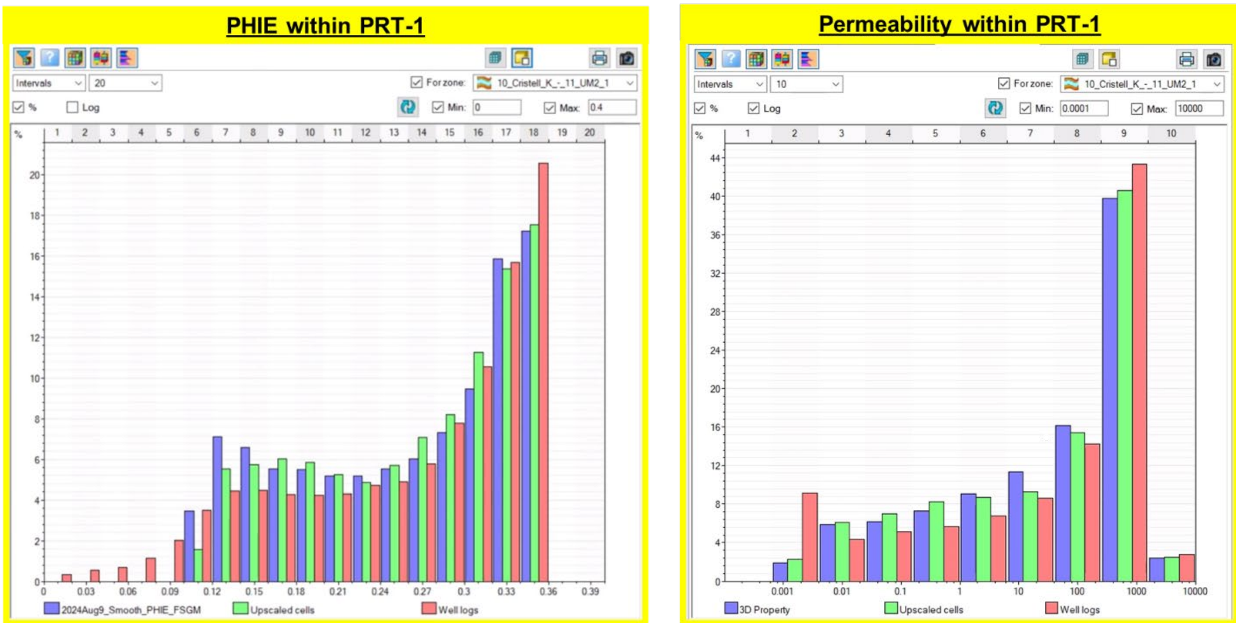

Figure 1-49 – Histograms comparing (a) porosity and (b) permeability from raw logs, upscaled logs, and the 3D property model specifically for PRT-1 in Zone_10_Cristell_K only.

[redacted]

Figure 1-50 – [redacted]

1.6.2.5 Net-to-Gross Estimation

Net to gross (NTG) is a 3D property estimated in the FSGM using petrophysical cutoffs. This property is used in the upscaling process to sample properties from the FSGM into a coarser model (reduced number of cells) for dynamic simulation. NTG is represented as an integer value of zero or 1, depending on the rock quality in each cell. A value of zero represents non-net and a value of one represents net rock. Non-net rock does not contribute to flow. A 3D NTG property was generated using a PHIE cutoff value of 18%, corresponding to a permeability of roughly 0.1 mD. Net rock is defined as rock having a PHIE greater than or equal to 18%. The NTG property was upscaled and used as input into the dynamic simulation.

1.7 Geomechanics

The state of stress and variations in stress with depth in the South Louisiana AOR were estimated using published literature and empirical correlations as described below. Additional site-specific information from the Class V stratigraphic test well, including cross-dipole sonic logs, triaxial compression tests on core samples, and modular formation dynamics tester (MDT) “mini-frac” data will further improve estimations of stress gradients and geomechanical properties.

1.7.1 Vertical Stress

Overburden or vertical stress is caused by the cumulative weight of all overlying formations and is calculated by integrating the bulk density log to the depth of interest. An offset well—SL 8355 No. 001 (SN 170250), with density log coverage across confining and injection intervals—was used to calculate the overburden stress gradient as a function of depth. Figure 1-51 shows the coverage of raw bulk density logs and the extrapolated bulk density at shallow depths in SN 170250. The calculated vertical stress curve resulting from the integration of bulk density is also shown.

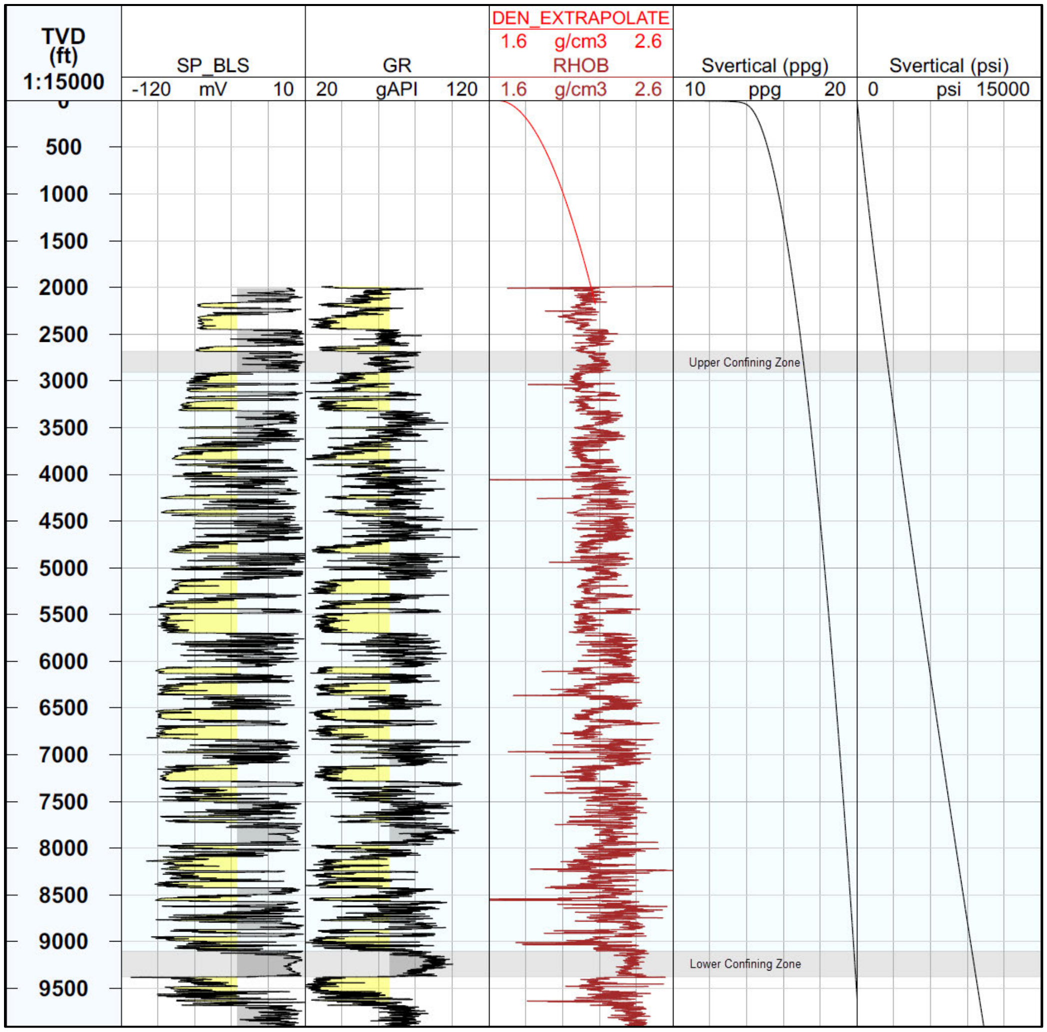

Figure 1-51 – Raw logs and calculated overburden / vertical stress in offset well SL 8355 No. 001 (SN 170250).

The average bulk density, vertical stress, and overburden gradient for the upper confining, injection, and lower confining zone intervals as encountered in offset well SN 170250 are summarized in Table 1-13.

Table 1-13 – Calculated vertical stresses using measured density log readings from offset well SL 8355 No. 001 (SN 170250).

Zone	Depth (ft, TVD)	Avg Density (g/cm^3)	Vertical Stress (psi)	Overburden Gradient (psi/ft)
Upper Confinement	2,683–2,906	2.182,890–2,927	0.898–0.901	
Injection	2,906–9,101	2.21	3,228–10,238	0.909–1.040
Lower Confinement	9,101–9,378	2.37	10,602–10,907	1.047–1.051

*g/cm^3 – grams per cubic meter

1.7.2 Elastic Moduli

Elastic moduli in the upper confining, injection, and lower confining zones will be calculated from measurements on core collected from the Class V stratigraphic test well. A representative sample of core plugs will undergo triaxial compressive strength testing to provide geomechanical properties such as Young's modulus, Poisson's ratio, and compressive strength.

1.7.3 Fracture Gradient

Fracture gradient (FG) was estimated using Eaton's equation, which is commonly accepted as the standard practice in the Gulf Coast. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore pressure gradient (PG). The input variables used in the analysis will be updated once site-specific data from the Class V stratigraphic test well becomes available.

Fracture gradients were calculated at two TVDs of 3,500 feet and 8,500 feet using Eaton's equation. These values were then interpolated to produce an FG curve that varies linearly with depth. This linear approach is validated by the findings of Althaus (1977), which utilized data from South Louisiana and offshore. The study demonstrated that fracture gradients increase linearly with depth within the normal fluid pressure window, providing confidence in the interpolation method used for constructing the FG curve.

Poisson's ratio values were derived using Figure 1-52 (Eaton, 1969), which illustrates how Poisson's ratio varies with depth across typical Gulf Coast lithologies. The values of Poisson's ratio obtained were 0.32 at a depth of 3,500 feet TVD and 0.41 at 8,500 feet TVD.

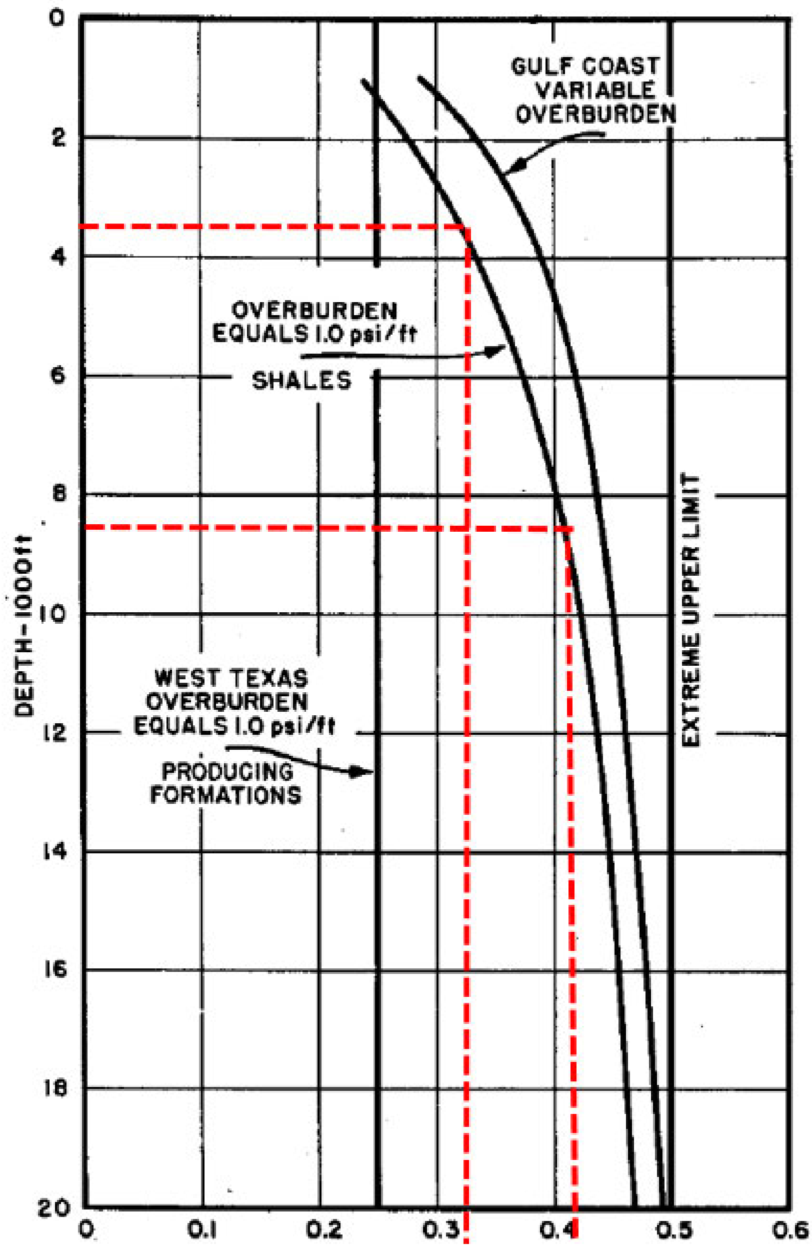

Figure 1-52 – Variation of Poisson's Ratio with Depth (Eaton, 1969)

The OBG was estimated as outlined in *Section 1.7.1* by integrating bulk density log measurements with the specified depths. The calculated OBGs were 0.91 psi/ft at a depth of 3,500 feet TVD and 1.02 psi/ft at 8,500 feet TVD.

A PG of 0.465 psi/ft was used, based on hydrostatic pressure trends observed across several South Louisiana fields, as documented by Nelson (2012). Sources for pressure trends in this study include drill stem tests (DSTs), mud weights, and bottomhole pressure data.

At a depth of 3,500 ft TVD, applying Eaton's equation with an OBG of 0.91 psi/ft and a Poisson's ratio of 0.32 yields an estimated FG of 0.67 psi/ft, as demonstrated in Equation 5.

(Eq. 5)

$$FG = \frac{\nu}{1-\nu}(OBG - PG) + PG$$

$$FG = \frac{0.32}{1-0.32}(0.91 - 0.465) + 0.465 = 0.67\ psi/ft$$

Similarly, at a depth of 8,500 ft TVD, using an OBG of 1.018 psi/ft and a Poisson's ratio of 0.41 results in an estimated FG of 0.85 psi/ft. The calculations are further summarized in Table 1-14.

Table 1-14 – Fracture Gradient Calculation Inputs and Results

Depth (ft, TVD)	Zone	Formation	Overburden Stress (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
3,500	Injection	Upper Miocene	0.91	0.465	0.32	0.67
8,500	Injection	Middle Miocene	1.02	0.465	0.41	0.85

The FG (psi/ft) curve generated as a linear function of TVD (ft) using the two data points above is presented in Equation 6 as:

(Eq. 6)

FG = 0.544 + 3.6e-5 * TVD

The calculated FG curve was applied across all lithologies and will be updated as more site-specific data becomes available. Since Poisson's ratio is generally higher in shales than in sandstones, the current calculation represents a conservative estimate of the FG in the shale and in the confining zones.

According to 40 CFR **§146.88(a)**, the maximum allowable pressure is based on the step-rate test results. A step-rate injectivity test will be performed on the injectors. Modular formation dynamics tester mini-frac tests will be performed on the Class V stratigraphic test well, which will give an estimate of the FG in the injection zone and confining zones ahead of the step-rate injectivity test performed on the injectors. If the step-rate injectivity test is unable to determine the FG, core measurements will be utilized in conjunction with the MDT mini-frac results to further calibrate and refine calculations based on Eaton's equation.

1.8 Injection Zone Water Chemistry

Publicly available data from the USGS National Produced Waters Geochemical Database (Ver. 3.0) is analyzed here to provide insight into general salinity and constituent ion components, as well as the variability of injection-zone water composition. Fluid analysis results from the Class V stratigraphic test well will provide site-specific measurements of total dissolved solids (TDS) and concentrations of ions from the proposed injection interval. Geochemical modeling in *Section 1.7* uses regional, publicly available data, which will be updated with the site-specific data once available.

The USGS National Produced Waters Geochemical Database was filtered to St. Charles, St. John the Baptist, Jefferson, and Lafourche Parishes, Louisiana, to examine a regional relationship between TDS and depth. The TDS (milligrams per liter (mg/L) or parts per million (ppm)) are plotted with associated depths in Figure 1-53. As demonstrated by the variability in the plot, the correlation between TDS and increasing depth is not strong. The TDS is generally between 100,000 mg/L and 150,000 mg/L over the range of injection interval depths at the proposed project site, as indicated by red dashed lines. An average value of 125,000 mg/L was used for modeling purposes.

The USGS data set was further filtered to capture the closest analogous samples and evaluate potential constituent ions and cations of the injection zone brine at the Libra project site. The analysis included 26 samples from 14 wells, all of which were from St. Charles Parish. The USGS IDs of the wells and the brine chemistry characteristics of these samples are presented in Table 1-15. A map of these samples in relation to the proposed project site is provided in *Appendix B*.

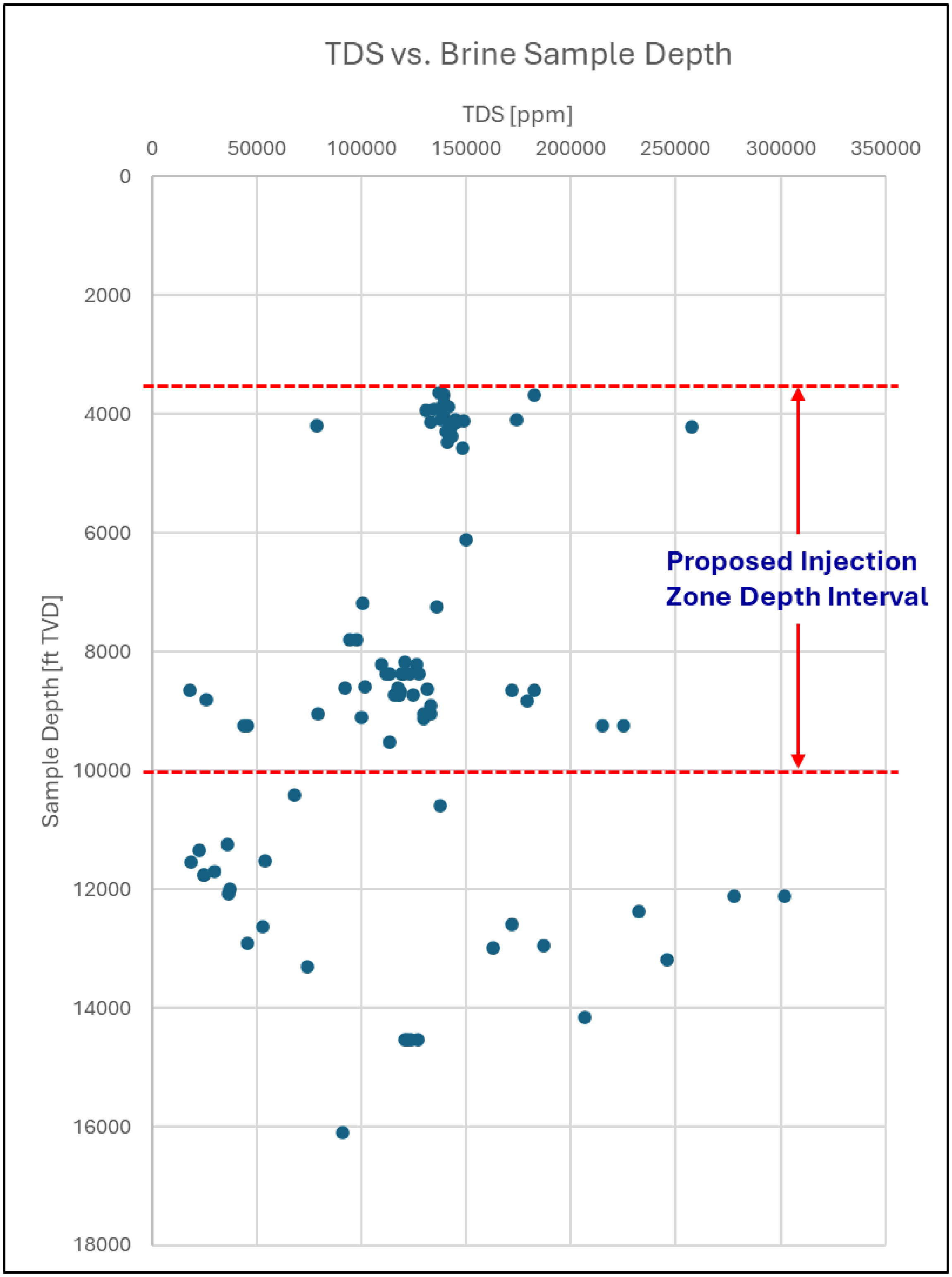

Figure 1-53 – Plot of TDS (ppm) vs. depth (ft) of nearby produced brine samples.

Table 1-15 – Analogous Produced Water Samples from the USGS National Produced Waters Geochemical Database

USGS ID	Serial No.	API No.	Depth Interval (ft)	Specific Gravity	pH	TDS (mg/L)
56826	41622	17089000570000	9,253-61	1.157	6.25	225,173
56827	41622	17089000570000	9,253-61	1.156	4.8	214,752
56828	33269	17089000560000	8,729-32	1.081	7.2	117,740
56829	33269	17089000560000	8,729-32	1.082	6.9	115,880
56830	33269	17089000560000	8,729-32	1.083	6.1	124,541
56831	33269	17089000560000	8,729-32	1.085	7	118,202
56832	33269	17089000560000	unknown	1.08	7	120,621
56833	80788	17089001700000	unknown	1.045	6.15	60,251
56834	31610	17089001690000	8,373-78	1.082	7	119,162
56835	31610	17089001690000	8,373-78	1.083	7.2	113,436
56836	31610	17089001690000	8,373-78	1.086	7.61	127,512
56837	31610	17089001690000	8,373-78	1.081	6.95	112,009
56838	31610	17089001690000	8,373-78	1.082	6.15	120,404
56839	31610	17089001690000	9,238-51	1.033	7.55	44,114
56840	30271	17089001640000	8,218-28	1.083	7.3	109,823
56841	30271	17089001640000	8,177-96	1.083	6.86	120,546
56842	30271	17089001640000	8,218-28	1.085	6.91	126,192
57128	85441	17089000260000	7,241-43	1.09	7.2	135,840
59038	33269	17089000560000	8,670-90	1.079	7.1	118,447
59039	41622	17089000570000	8,612-32	1.079	6.94	117,508
60509	29742	17089000120000	6,111-25	1.092	6.4	149,727
60510	32979	17089000390000	unknown	1.071	6.6	122,590
60511	31488	17089000420000	8,367-72	1.078	6.4	122,789
60512	33723	17089000450000	9,238-51	1.03	6.9	45,439
61940	101362	17089000740000	8,804-24	1.026	7.6	26,122
61941	62548	17089000780000	8,582-unk	1.068	6.6	101,521

1.9 Baseline Geochemistry

The mineral-brine-CO_2 interactions that occur during CO_2 sequestration lead to the alteration of host rock, and eventual equilibrium in the mineral-brine-CO_2 system. Chemical modeling and laboratory experiments show that these reactions and eventual equilibria are driven by the specific mineralogy of the target formation, the composition of the brine, the acidity of the brine-CO_2 mixture, and the pressure and temperature in the subsurface. This section covers the modeling of the mineral-brine-CO_2 system across the mineralogical facies associations present for the subject site.

1.9.1 Methods

Simplified, batch kinetic simulation experiments (models) were created for each facies present at the subject location. The models use phase thermodynamic data in the PHREEQC Lawrence Livermore National Laboratory Database and reaction kinetics from Palandri and Kharaka (2004) to model the mineral-brine-CO_2 interactions. Each simulation experiment is isothermal, with the temperature set to match the subject location and depth. The pressure for each simulation experiment is also static and set to match the subject location and depth.

The thermodynamic model is based on local equilibrium for the minerals and ions in an aqueous phase. The kinetic calculations assume that abundant CO_2 is supplied to the system during the simulation and that any consumed molecule of CO_2 is replaced. These simplifying assumptions align with the reality of the physical system in that continuous injection allows for an abundant gas supply to the system.

1.9.2 Brine Geochemistry

The brine composition used for the simulations is derived from the USGS National Produced Waters Geochemical Database, which contained 26 samples of produced water from Miocene reservoirs in the Good Hope and Pontchartrain West Block fields of St. Charles Parish. The available analytical values were averaged to create a composite brine used in the mineral kinetics batch models for the confining and injection zones. The composition of the composite brine is shown in Table 1-16.

Table 1-16 – The brine composition used for modeling, which was created by averaging compiled data from the USGS National Produced Waters Geochemical Database.

Species	Concentration	Units
pH	6.8	
Specific Gravity	1.08	
TDS	116,552	mg/l
Ba	N/M	mg/l
HCO_3	475	mg/l
Ca	1,920	mg/l
Cl	70,089	mg/l
Fe_{Tot}	69	mg/l
Na	42,905	mg/l
Mg	440	mg/l
SO_4	117	mg/l
Si	8	mg/l

1.9.3 Mineral Geochemistry

Despite the well-understood nature of the stratigraphy in the vicinity of the subject site, published X-ray diffraction (XRD) data across the target formations are scarce. The mineral composition used in the simulation for the injection zone is from a BEG database record containing four samples from the TWEEDEL UNIT V NO. 001 (SN 48231) well. The data are normalized to 100% to account for the 27.3% porosity. The measured values are supported by lithologic descriptions and generalized XRD data from Hovorka and Knox (2003), Loucks and Moseley (1977), and McGuire and Grigsby (2009).

The mineral composition used in the simulation for the Rob E upper confining and Cris I lower confining zones comes from petrographic analysis of the NAVARRE NO. #A-1 (SN 72873) (Watson, 1965) in Acadia Parish, Louisiana. Mineral compositions of the confining units are supported by lithologic descriptions from Hovorka and Knox (2003) and Meckel and Trevino (2019), as well as from XRD analyses of silicate rocks from similar depositional environments published by Weaver (1977). The smectite-illite ratios in the confining intervals were estimated using the depth and transformation relationship published in Freed (1979). The values used in the simulation experiments are shown in Table 1-17.

1.9.4 Models

Three geochemical models were created—one each for the upper and lower confining zones and one for the injection zone. Each of the models uses pressures and temperatures calculated using a generalized depth for the interval.

The reaction processes expected were modeled as a product of thermodynamic equilibrium and kinetic reactions using PHREEQC. The models were created as simplified, 1D batch models that occur at pressure and temperatures dictated by their stratigraphic position. The models assume a pressure gradient of 0.465 psi/ft and a temperature gradient of 1.40°F/100 ft with a mean annual surface temperature of 64°F. The injected volume of CO_2 was assumed to fill the pore space.

Table 1-17 – The estimated mineral compositions used to model each of the stratigraphic units.

Facies Name	Upper Confining Zone	Injection Zone 1	Lower Confining Zone
Modeled Depth (ft)	3,400	6,600	9,850
Stratigraphic Unit	Rob E	Upper–Middle Miocene	Cris I
Quartz	35.5	82.7	29.5
Calcite	0.0	1.5	0.0
Plagioclase (albite)	3.0	4.4	3.0
Feldspar (anorthite)	0.0	0.0	0.0
K-Feldspar	4.5	4.1	4.5
Smectite	33.6	0.4	9.6
Illite	12.0	0.0	24.0
Kaolinite	2.4	2.0	14.4
Chlorite	0.0	0.0	0.0
Pyrite	0.0	0.7	0.0

1.9.5 Results

Across all the models, the results show mild reactivity within the mineral-brine-CO_2 system. Reactions begin to occur after a few seconds of contact and accelerate through the first several hundred years of simulation time. From 1,000–10,000 years, the reactions approach equilibrium. The precipitation and dissolution of all mineral constituents of the simulation experiments are shown in Figure 1-54. The precipitation and dissolution of minor mineral constituents are shown in Figure 1-55.

In general, the confining intervals show the precipitation of quartz, smectite, k-feldspar, and a minor amount of dolomite. The simulations also show the dissolution/alteration of illite. The alteration of accessory minerals in the confining zones is vigorous after several days of reaction time, and approaches equilibrium in 10 years.

The injection interval simulation shows the dissolution of albite, k-feldspar, and calcite during the injection period, with the precipitation of dolomite and precipitation/alteration of smectite. After the injection time frame, calcite and quartz precipitate.

Overall, the volume of clay species in the injection zone is subordinate to the quartz fraction. Thin-section data from the facies indicate that the high-porosity injection zone is quartz grain-supported, which suggests that alteration, dissolution, and precipitation of the subordinate mineral species will have limited impact on the porosity. In the confining intervals, the precipitation of clay minerals is likely to support seal capacity through pore occlusion. The models show an overall low percentage of alteration in the host rock.

A number of necessary assumptions used in this modeling work led to the models overrepresenting the speed and amount of alteration, compared to what will occur in the natural system. The equilibrium rates in the subsurface are expected to be much slower than those predicted. This slower rate is primarily due to the reactions taking place within the pore system of a rock volume as opposed to the simulated batch reactor. The pore system influences concentration gradients and decreases the surface area of each mineral available for reaction, leading to slower reaction rates. Furthermore, geologic and hydrologic factors such as fluid flow paths may alter ion availability and system reactivity. Therefore, the modeling work in this section is an analysis of the upper bound of reactivity expected in the system.

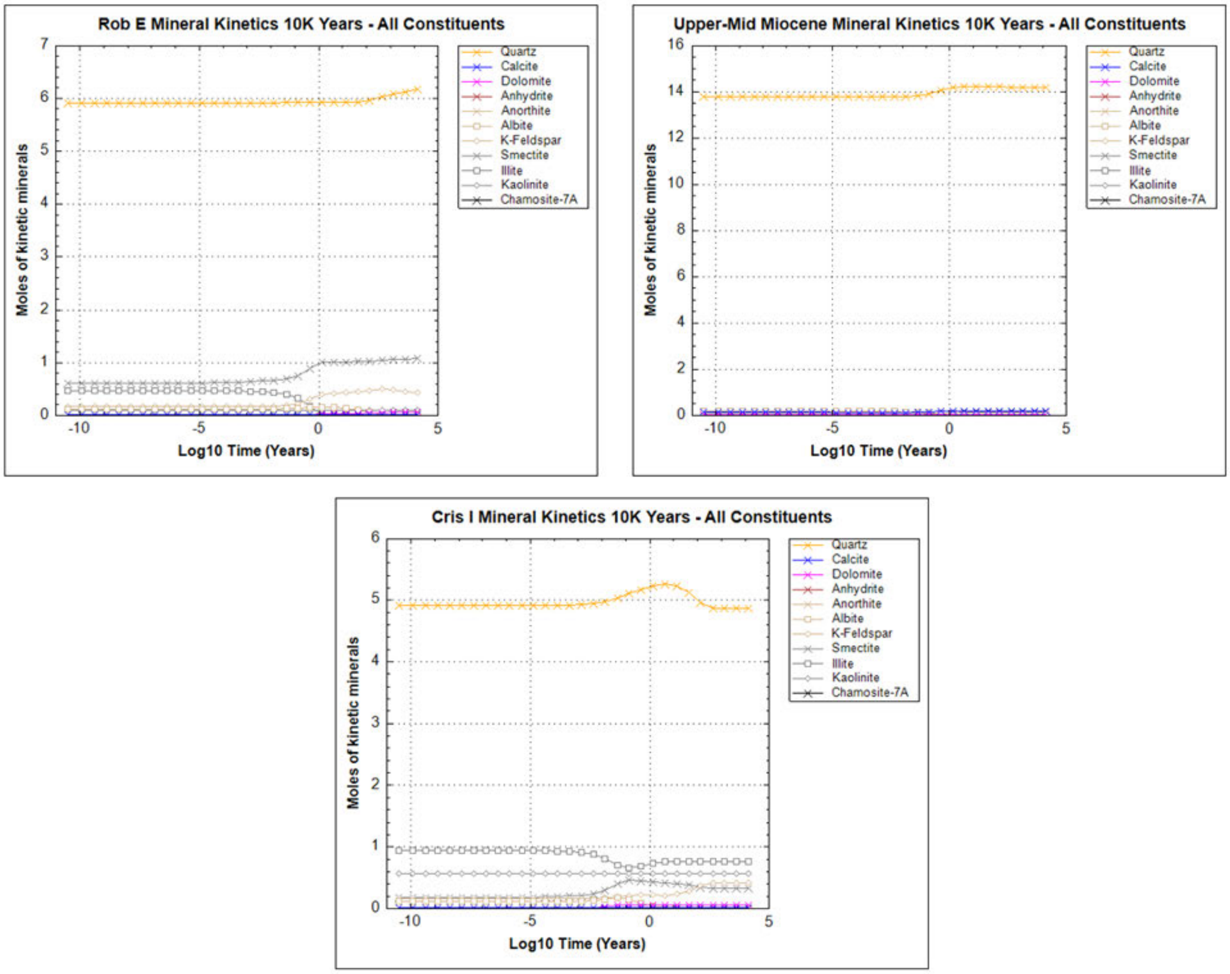

Figure 1-54 – The results of the batch simulations for all mineral constituents are shown by unit. The x-axis is log10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.

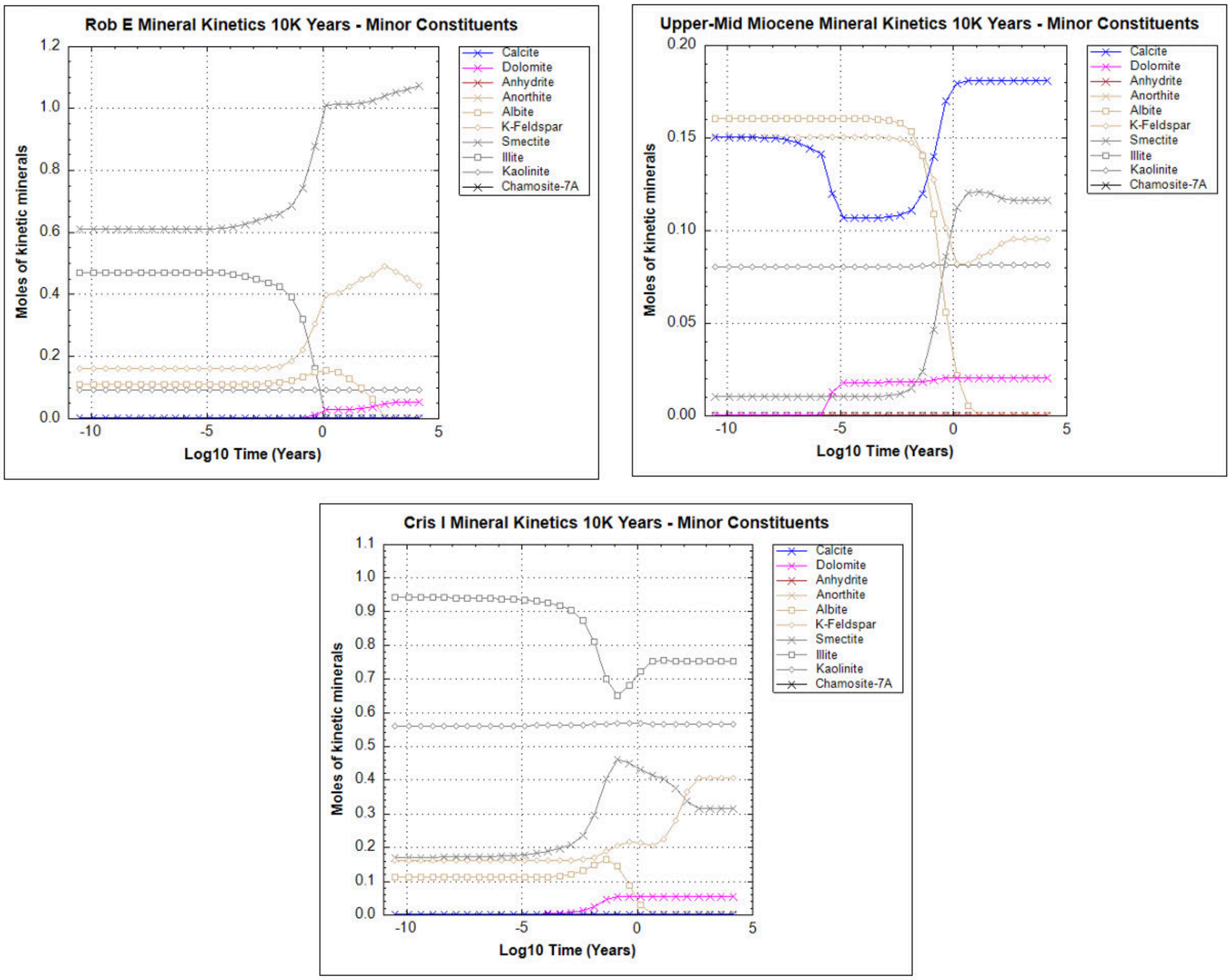

Figure 1-55 – The results for minor mineral phases of the batch are shown by unit. The x axis is log10 time in years. The reaction time spans from 0.001 seconds to 10,000 years.

1.10 Hydrology

A hydrologic review of St. Charles Parish was conducted for the Libra project area to properly characterize and protect potential Underground Sources of Drinking Water (USDWs) in Louisiana. The study reviewed publicly available material published by the LDENR, USGS, and literature from peer-reviewed journals. The LDENR online database supplied helpful documents regarding water well and groundwater information. The USGS studies contributed to the hydrologic evaluation as well as the source figures included in this section.

St. Charles Parish is located in southern Louisiana, immediately west of the city of New Orleans. The area encompasses approximately 410 sq mi, with nearly 33% of the parish covered by water bodies as shown in the regional Louisiana parish map in Figure 1-56. This report reflects the water resources and hydrology within the parish.

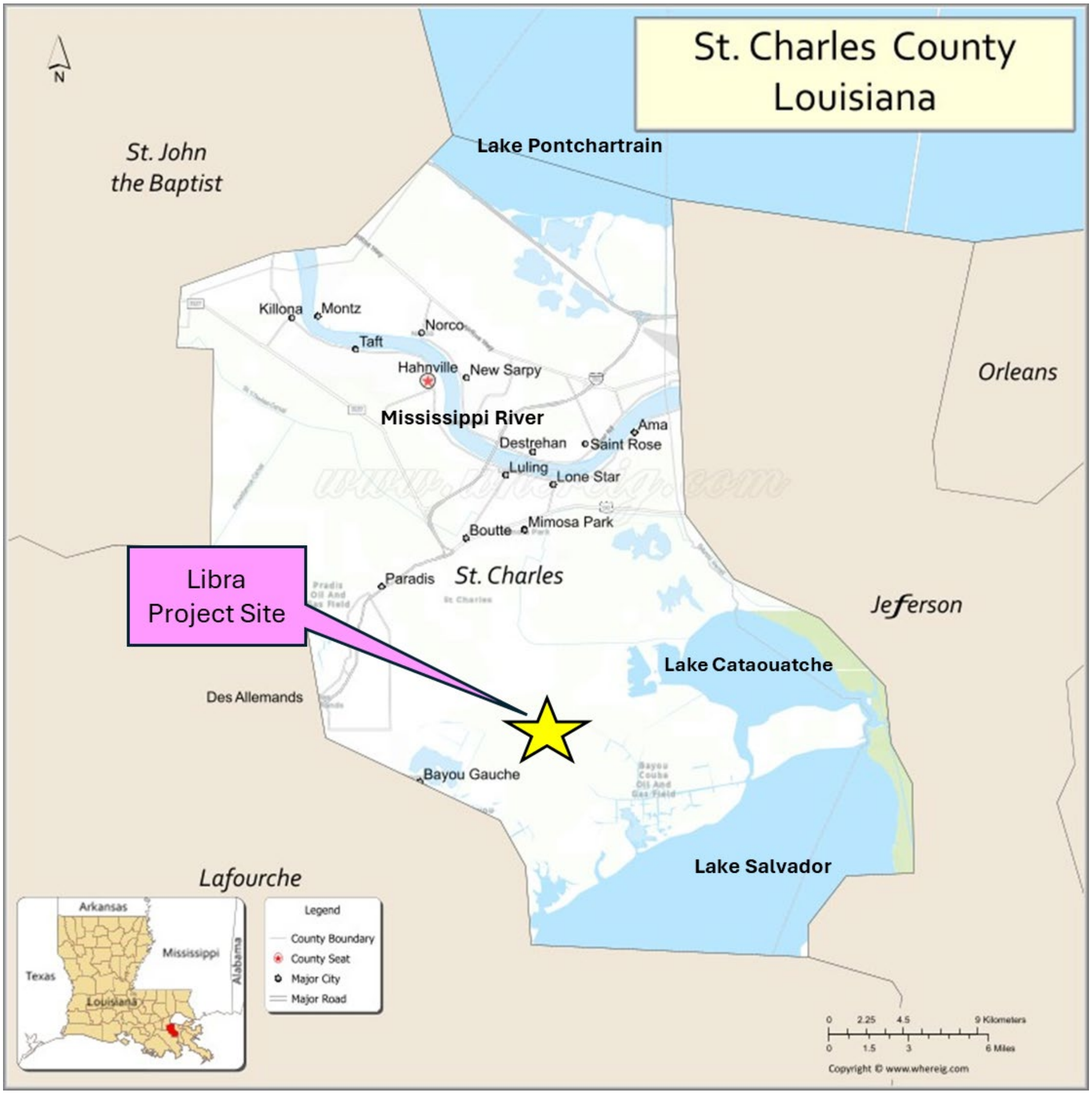

Figure 1-56 – Location of the Libra project, starred on the St. Charles Parish map.

1.10.1 Area of Study

Groundwater resources include three aquifers that make up the total water system for St. Charles Parish. These aquifers, in order of shallowest to deepest, are the Gramercy aquifer, the Norco aquifer, and the Gonzales-New Orleans aquifer. These aquifers supply the entire parish with water for potable, industrial, and irrigation purposes. However, the aquifers are primarily used for industrial purposes (>99%).

Surface water resources include the Mississippi River, which runs within the parish and provides another source of water. Several lakes are present including Lake Salvador, Lake Cataouatche, and Lake Pontchartrain. The Mississippi River is the primary source of potable water for the parish. A water resource map of St. Charles Parish is shown in Figure 1-57.

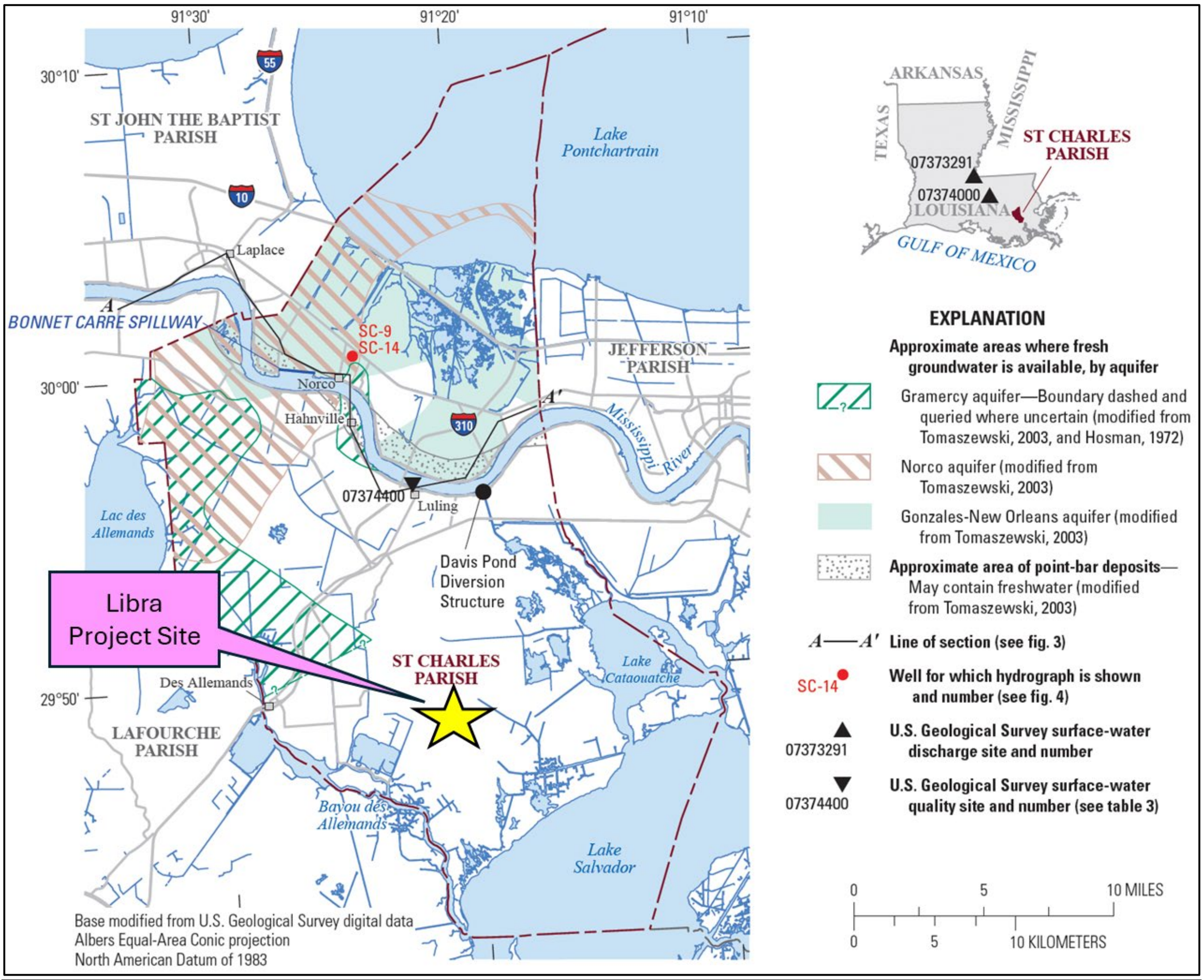

Figure 1-57 – Map showing the area of study (modified from White and Prakken, 2015).

1.10.2 Base of USDW Determination

Within a 10-mi search radius of the proposed injection sites, a query in the Strategic Online Natural Resources Information System (SONRIS) database returned 117 wells with LDENR-assigned values for the base of the USDW. The eight closest data points that surround the Libra project property have base-of-USDW values ranging from 940 ft to 1,195 ft TVD. These eight offset wells, along with their state-approved USDW depth and approximate distance from the injection sites, are detailed in Table 1-18.

Table 1-18 – Eight closest offset wells to the proposed injection sites, with USDW depths assigned by the LDENR Injection and Mining division (retrieved from SONRIS, 2024).

Well Name / No.	Serial No. (SN)	LDENR-Designated Depth of USDW (ft, TVD)	Distance from Injection Sites (mi.)
ST CHARLES LD CO A RA B NO. 009	115365	1,050	2.2 mi S
LYDIA B SIMONEAUX ET AL SWD NO. 002	48599	1,195	2.7 mi NE
T B SELLERS NO. 003	95696	1,070	2.9 mi SW
JOSEPH RATHBORNE LD & LBR NO. 002	50764	1,110	3.3 mi N-NW
JOESPH RATHBORNE LD LBR CO NO. 001	48783	1,080	4.0 mi N-NE
DELTA SEC CO INC NO. 048	43270	940	5.0 mi E-SE
PETER REISCH NO. 001	28543	1,025	5.1 mi NW
W H TALBOT ETAL NO. 001	61848	1,120	5.6 mi N

Using the LDENR Office of Conservation's Injection and Mining Division published handbook *USDW Search*, the USDW was picked in 11 additional offset wells with shallow-reaching logs, to increase control points and more precisely estimate the base of the USDW depth at the injection locations. Per the state-defined guidelines for USDW determination, the base of the USDW was picked in these 11 offset wells by adhering to the following criteria:

1. A deep induction log greater than 2.5 ohms used for USDW areas between 1,000–2,000 ft; a deep induction log greater than 3 ohms, for USDW areas shallower than 1,000 ft.

2. The base of the USDW is established at the base of the sand unit that contains the lowermost USDW with an isolating shale beneath it.

3. One-hundred feet of net shale must exist between the top of the zone and the base of the USDW.

The closest USDW data point picked from among the 11 offset wells was the WATERFORD OIL CO. NO. 001 (SN 81236). The base of USDW was determined to be 1,222 ft TVD in this well, located 2.5 mi east-northeast of the injection site. Moreover, a depth structure map was generated using all 19 total control points (8 wells with LDENR-assigned USDW values + 11 offset wells with interpreted USDW picks), included in *Appendix B*. The following section provides further groundwater and surface water resource details about St. Charles Parish.

1.10.3 Groundwater Resources

As noted in *Section 1.10.1*, the three primary aquifer systems present in the Libra project area, from shallowest to deepest, include the Grammercy aquifer, Norco aquifer, and Gonzales-New Orleans aquifer. The SONRIS database was queried for nearby groundwater wells actively registered to these aquifer systems, with the closest wells to the project site identified in Figure 1-58. General groundwater flow direction is to the northeast, towards New Orleans. The following sections describe in more detail the aquifer systems and their freshwater quality, supply, and usage.

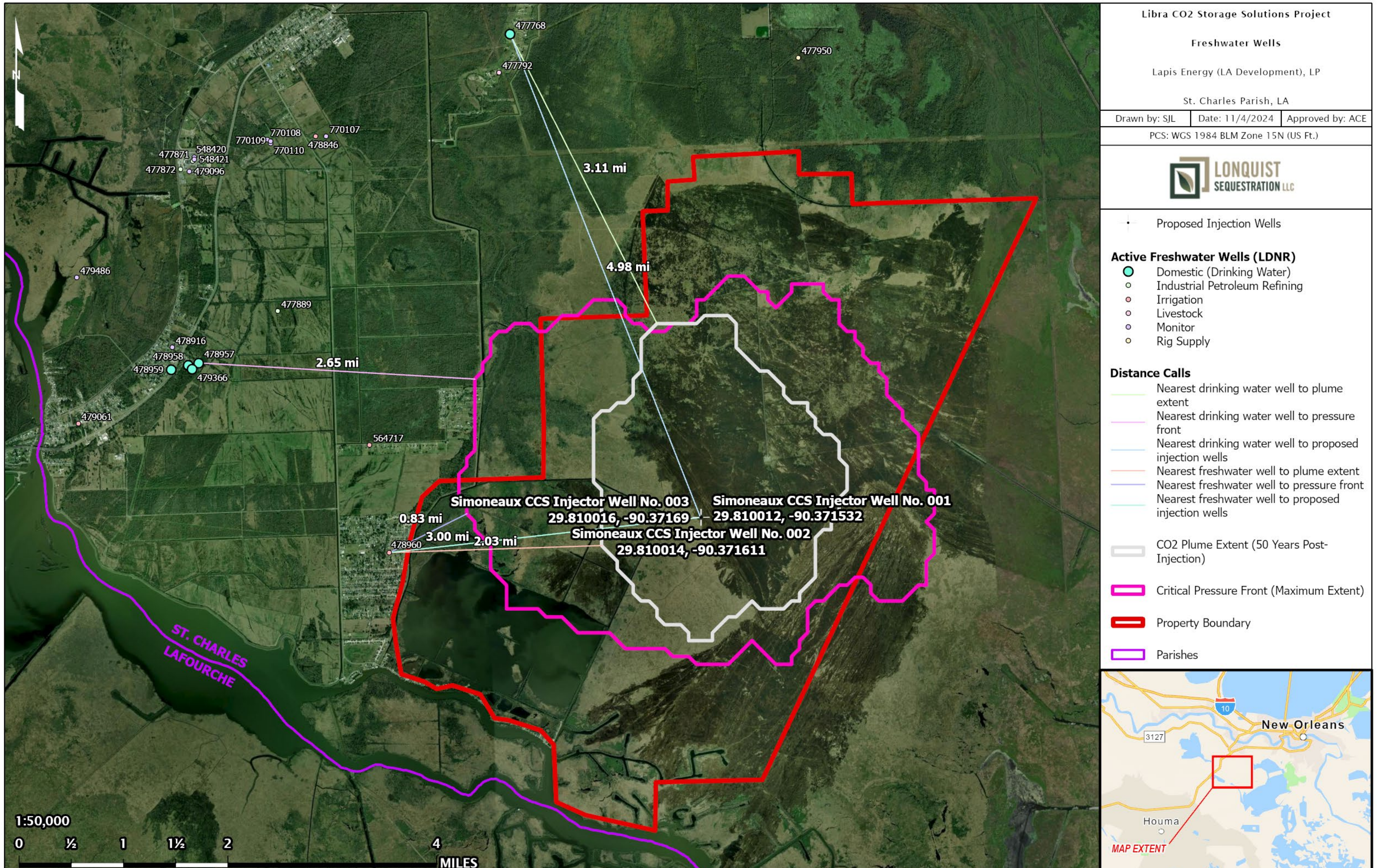

Figure 1-58 – Groundwater registered wells producing from the three primary aquifer systems, with their distance from the Libra project site. Groundwater wells were identified in SONRIS, accessed June 2024.

Gramercy Aquifer

The Gramercy aquifer contains some freshwater in the western St. Charles Parish and in a localized area near Norco and Hahnville (White & Prakken, 2015), but primarily contains saltwater in this parish. This aquifer is the shallowest aquifer in the parish, is primarily made up of coarse sand, and is nearly nonexistent in the northern section of the parish. The Gramercy is between 100–250 ft below the National Geodetic Vertical Datum of 1929 (NGVD 29) and is approximately 150 ft thick at its thickest. The aquifer runs adjacent to the Mississippi River and is hydraulically connected to the river via a point-bar deposit in the vicinity of Hahnville (7–8 mi north of the Libra project's northern property boundary). A point-bar deposit is an eroded area of deposition where a cut bank occurs. Water levels are often variable seasonally.

State well-registration records listed 27 active water wells screened in the Gramercy aquifer in St. Charles Parish in 2014, including 12 domestic, 9 irrigation, 3 industrial, and 3 for public supply (White & Prakken, 2015). These wells were observed to yield 25–500 gallons per minute (gal/min). Water in the Gramercy aquifer varies from a mixed calcium and magnesium bicarbonate type updip in northern St. Charles Parish, to a sodium-chloride type downdip, near the project. The quality of the water itself changes vertically due to leakage. The water is generally hard with some salt content, and has been used to a limited extent in the past for domestic and livestock supply (Curole & Landry, 2015).

Norco Aquifer

The Norco aquifer is located in the northwestern section of the parish. Structural contour data has displayed that the top of the Norco aquifer is between 250–400 ft below the NGVD 29 within St. Charles Parish. The thickness of the aquifer varies significantly from 25–275 ft thick and contains sand that is coarse to fine grained in nature. While water levels do fluctuate, it was observed that the level increased over a 40-plus year span starting in the 1950s. In 2014, the state recorded 26 wells, with 14 wells used for industrial means, 8 for irrigation, and 4 for domestic needs. The wells range in depth from approximately 300–450 ft. Water yield rates have been reported from as little as 175 gal/min to as much as 2,000 gal/min. Water in the Norco aquifer varies from a sodium-bicarbonate type to a sodium-chloride type. Where groundwater is fresh, hardness ranges from 40–60 mg/L of calcium carbonate; hardness increases with salinity to more than 500 mg/L. Iron concentration is generally less than 500 micrograms per liter. Dissolved solids concentration ranges from 750–1,000 mg/L where the water is fresh and exceeds 2,500 mg/L where the water is brackish. The color of the water in the aquifer ranges from 5–180 platinum cobalt units (PCU) (White & Prakken, 2015).

Gonzales-New Orleans Aquifer

The Gonzales-New Orleans aquifer is located in both the southern and northern sections of St. Charles Parish. The presence of saltwater has been verified in the southern half while the northern half is generally regarded to be freshwater. The downdip limit of freshwater is approximately 4 mi north of the northern property boundary of the Libra project. Structural contour data indicates that the depths range from 450 ft below the NGVD 29 near Lake Pontchartrain to more than 800 ft below the NGVD 29 near Lake Cataouatche. The thickness of the aquifer ranges from 175–325 ft and thins to just 50 ft to the south toward the Gulf of Mexico. The aquifer is comprised of fine to very fine sand grains. Three wells were screened and recorded in the vicinity of the aquifer. One well is used for industrial means, one for irrigation, and one for domestic needs, with all the well depths occurring between approximately 670–750 ft. One of these wells had reported a yield of 1,293 gal/min (White & Prakken, 2015). Groundwater withdrawals in the parish from the Gonzales-New Orleans aquifer exceeds 3.70 million gal/day, which is used solely for industrial purposes. The water quality varies from a sodium-chloride type in the saltwater areas, near the Libra project area, to a mixed sodium-bicarbonate-chloride type in the freshwater areas in the northern portion of the parish. Freshwater hardness ranges from about 10–40 mg/L as calcium carbonate, whereas saltwater hardness is measured to be more than 300 mg/L (White & Prakken, 2015).

1.10.4 Surface Water Resources

The following section details the surface water (i.e., rivers and lakes) resources in St. Charles Parish.

<u>Rivers</u>

In the early 2010s, the primary source of freshwater for St. Charles Parish was the Mississippi River. In 2010, about 2,470 million gallons per day (Mgal/d) of surface water was withdrawn in the parish, including approximately 503 Mgal/d for industrial use and 1,960 Mgal/d for power generation (White & Prakken, 2015). Much smaller quantities of withdrawn water were used for livestock and public supply uses. With the Mississippi River accessible to civilized communities, the water quality is often varied due to the influence of human and natural environmental processes such as runoff, discharge, and contamination from a variety of sources. Potable water is supplied by the Mississippi River after it is treated by an East Bank facility (7 Mgal/day capacity), or the West Bank plant (9 Mgal/day capacity) (Curole & Landry, 2015). No major tributaries or distributaries are noted from the river in the parish.

The collection of water samples from the late 1950s to the late 1990s deemed the water to be generally hard. The pH and quantity of chloride, sulfate, and iron did not rise above the secondary maximum contaminant levels (SMCLs), while the dissolved oxygen levels did not drop below 5 mg/L. Two diversion structures, the Bonnet Carre Spillway and the Davis Pond Freshwater Diversion Structure, are located on the Mississippi River in St. Charles Parish (White & Prakken, 2015). The Bonnet Carre Spillway is located nearly 30 mi north of New Orleans. It is the furthest southern floodway in the parish and can divert up to 250,000 cubic feet per second (ft^3/s) from the Mississippi River. The Davis Pond Freshwater Diversion Structure is located near Luling, Louisiana. The structure has a number of culverts and pumps that change the flow of the freshwater at rates of more than 10,000 ft^3/s.

Lakes

The largest lake that skirts the northeastern edge of the parish is Lake Pontchartrain, which spans approximately 630 sq mi and has an average depth of 11 ft. The deepest part of the lake has been recorded at 65 ft. The salinity of the lake is continuously changing due to its communication with the Gulf of Mexico.

Lake Salvador and Lake Cataouatche are located in the south and southeastern portion of the parish, respectively, and are connected via a small spillway. Lake Salvador encompasses an area of nearly 70 sq mi and is, to some extent, hydraulically connected to the Gulf of Mexico, while the area of Lake Cataouatche is just under 15 sq mi.

1.11 Site Evaluation of Mineral Resources

The following sections detail the oil and gas wells in and surrounding the greater Libra project area.

1.11.1 Inactive Mines Near the Proposed Injection Sites

A search using public data provided by the USGS Mines and Quarries Geodatabase was conducted. An inactive mine shaft (5594146) located outside the 5-mi radius was identified and located at a distance of 5.16 mi north of the area boundary. Figure 1-59 shows the enhanced location of the mine shaft, while Figure 1-61 shows the spatial relationship between the area boundary and the identified mine shaft. The USGS has indicated the location of this mine shaft from a map of Hahnville dated 1891. This shaft was likely exploratory in nature and was not further developed. No surface mineral impacts from the mine shaft will occur from the Libra project.

Figure 1-59 – Enhanced image of the mine shaft (5594146) identified in a query of the USGS Mines and Quarries Geodatabase.

1.11.2 Unnamed Geothermal Occurrence Near the Proposed Area Boundary

A search using public data provided by the USGS Mineral Resources Geodatabase was conducted. A report made on November 18, 1983, by the Louisiana Geological Survey identified a Geothermal Test Location located 4.84 mi north of the area boundary. Louisiana State University and the Louisiana Geological Survey have evaluated the site and determined it to be non-viable. This has resulted in the unnamed site being labeled as “Not Significant,” and no further development such as surface trenching, adits, shafts, drill holes, geophysics, geochemistry, or geologic mapping has occurred. A home was constructed on top of this test site in 1989. Figure 1-60 shows the enhanced location of the Geothermal Test Location, and Figure 1-61 shows the spatial relationship between the area boundary and the Geothermal Test Location. No impacts from this location will occur from the Libra project.

Figure 1-60 – Enhanced image of the Geothermal Test Location identified in a query of the USGS Mineral Resources Geodatabase.

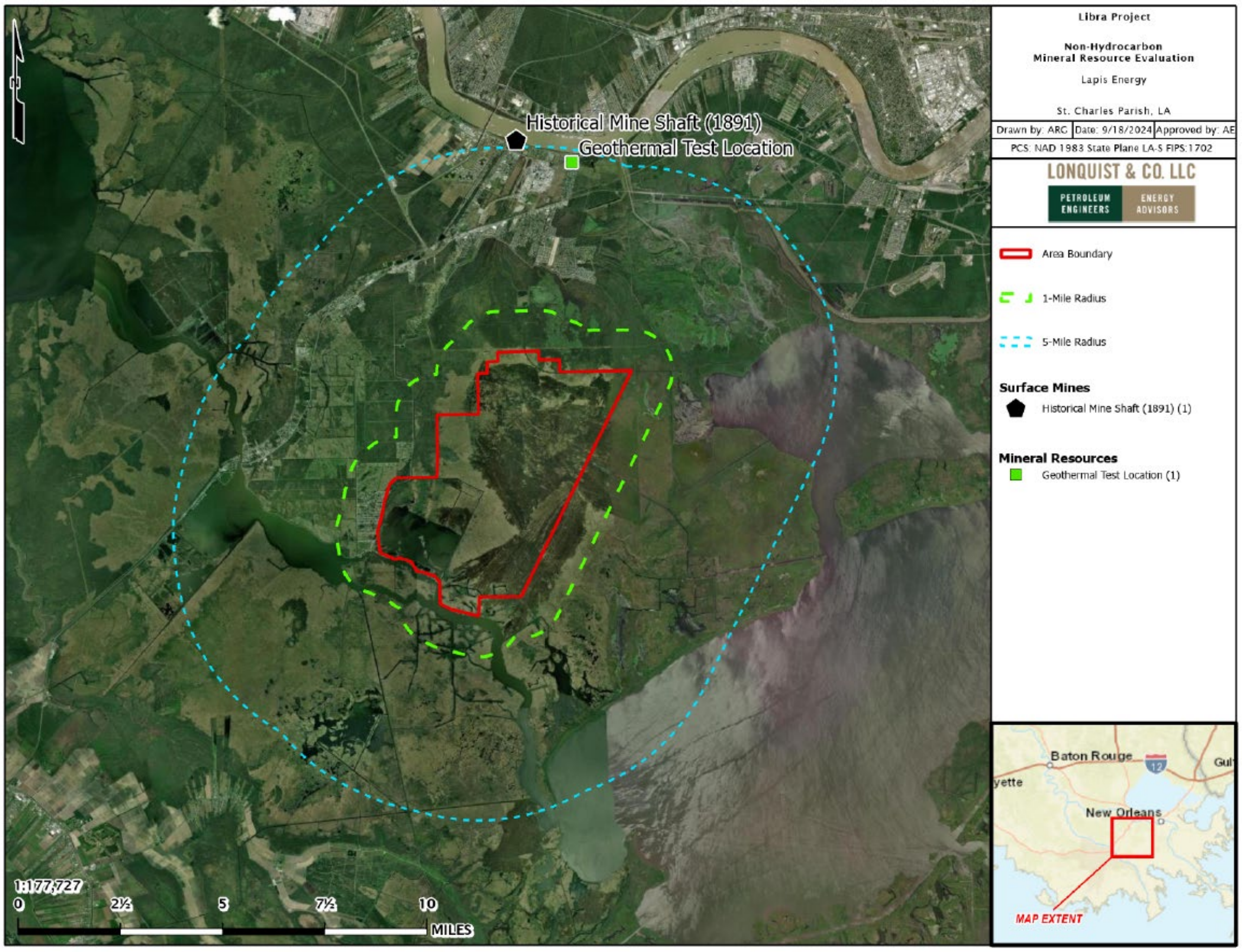

Figure 1-61 – Mineral Resources Evaluation Map displaying the location of the mine shaft and Geothermal Test Location relative to the Libra project area boundary.

1.11.3 Underground Mineral Resources

A search for subsurface mineral production was conducted using publicly available data from the LDENR (SONRIS and Document Access). The data was used to locate current and historical production zones within a 5-mi radius of the proposed area boundary.

The data included locations, perforations, production history, and current well status. Meeting the radial distance set from the area boundary, a total of 1,055 wells were identified. Figure 1-62 plots the locations of all the wells within the 5-mi radius. Table 1-19 provides a summary of the status count of the wells within the 5-mi investigation radius.

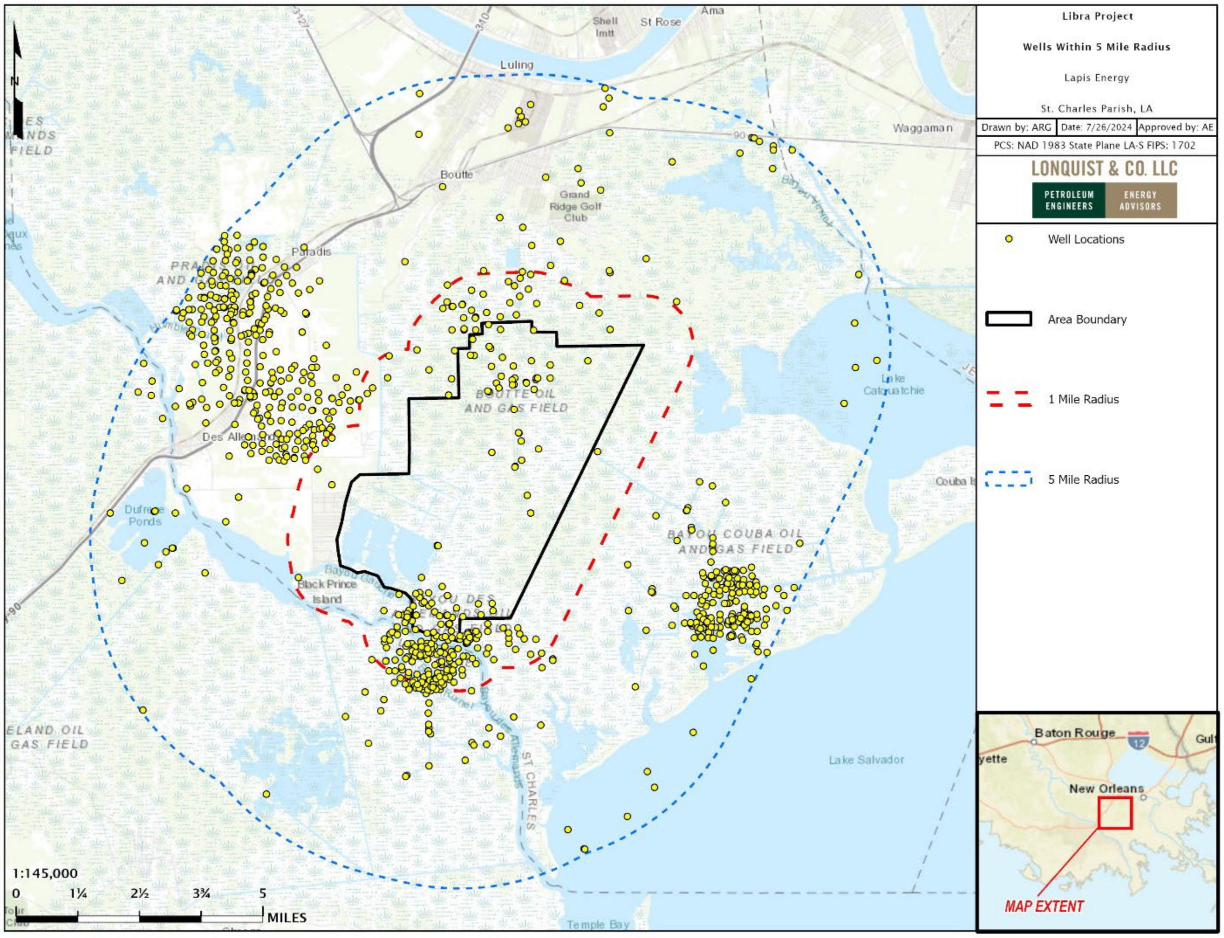

Figure 1-62 – All wells plotted within a 5-mi investigation radius of the Libra project area boundary.

Table 1-19 – Well count by status of all wells within a 5-mi investigation radius of the Libra project Area boundary.

Well Status	Total
ACT 404 ORPHAN WELL - ENG GAS	4
ACT 404 ORPHAN WELL - ENG NO PRODUCT SPECIFIED	4
ACT 404 ORPHAN WELL - ENG OIL	3
ACTIVE - PRODUCING GAS	13
ACTIVE - PRODUCING OIL	25
ACTIVE - INJECTION NONHAZARDOUS INDUSTRIAL	6
ACTIVE - INJECTION PRODUCED SALT WATER	14
DRY AND PLUGGED GAS	2
DRY AND PLUGGED NO PRODUCT SPECIFIED	247
DRY AND PLUGGED OIL	1
PA-35 TEMPORARY INACTIVE WELL TO BE OMITTED FROM PROD. REPORT GAS	15
PA-35 TEMPORARY INACTIVE WELL TO BE OMITTED FROM PROD. REPORT OIL	11
PERMIT EXPIRED	84
PLUGGED AND ABANDONED DRY GAS	1
PLUGGED AND ABANDONED GAS	70
PLUGGED AND ABANDONED NO PRODUCT SPECIFIED	147
PLUGGED AND ABANDONED OIL	246
PLUGGED BACK - NO PERFORATIONS - NO LUW NO PRODUCT SPECIFIED	1
REVERTED TO SINGLE COMPLETION NO PRODUCT SPECIFIED	29
REVERTED TO SINGLE COMPLETION OIL	3
SHUT-IN DRY HOLE - FUTURE UTILITY NO PRODUCT SPECIFIED	1
SHUT-IN PRODUCTIVE - FUTURE UTILITY GAS	24
SHUT-IN PRODUCTIVE - FUTURE UTILITY OIL	100
UNABLE TO LOCATE WELL - NO PLUGGED AND ABANDONED GAS	1
UNABLE TO LOCATE WELL - NO PLUGGED AND ABANDONED NO PRODUCT SPECIFIED	2
UNABLE TO LOCATE WELL - NO PLUGGED AND ABANDONED OIL	1

1.11.4 Distribution of Perforated Intervals

Figure 1-63 plots the distributions of perforation depth and distances from the centroid of the Libra project's lease boundary. The horizontal lines show the shallowest and deepest base for both the upper confining and lower confining zones. The base for the UCZ spans from 2,596 ft to 3,642 ft, while the base of the LCZ ranges from 8,239 ft to 10,135 ft.

Figure 1-63 – Well perforation distribution in relation to the injection zone; the range of depths for the upper and lower confining zones in the project area are represented by the shaded green areas.

1.11.5 Nearby Artificial Penetrations with Perforations Above the Injection Zone

All perforated intervals within 5 mi of the proposed area boundary above the proposed injection zone were located and reviewed. Table 1-20 includes the wells returned from the query within the specified area of investigation, containing 7 active injectors, 224 plugged dry holes, 4 orphan wells, and 3 shut-in/temporarily abandoned wells.

Table 1-20 – Oil and gas wells within 5 mi of the area boundary with perforations above the injection zone.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
79525	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,438	9,681	0.50
125786	ST CHARLES LD & TRUST CO C	Dry/Plugged	0	0	3,457	9,993	0.95
168952	L B SIMONEAUX ET AL	Dry/Plugged	0	0	3,456	9,688	1.02
186005	L B SIMONEAUX	Dry/Plugged	0	0	3,456	9,688	1.11
186913	L B SIMONEAUX	Dry/Plugged	0	0	3,456	9,688	1.11
151705	SIMONEAUX	Dry/Plugged	0	0	3,429	9,979	1.19
108246	MRS L B SIMONEAUX ET AL	Dry/Plugged	0	0	3,404	9,727	1.22
193508	W R WHITE ET AL	Dry/Plugged	0	0	3,437	9,384	1.80
88612	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,282	9,266	2.05
972437	LYDIA B SIMONEAUX ET AL SWD	Dry/Plugged	2,610	2,630	3,372	9,417	2.06
972437	LYDIA B SIMONEAUX ET AL SWD	Dry/Plugged	2,440	2,630	3,372	9,417	2.06
151856	MORNA E DUSENBURY ET AL	Dry/Plugged	0	0	3,437	9,384	2.08
970047	LYDIA B SIMONEAUX ETAL SWD	Dry/Plugged	2,393	2,423	3,355	9,444	2.24
970047	LYDIA B SIMONEAUX ETAL SWD	Dry/Plugged	1,850	1,880	3,355	9,444	2.24
47529	L B SIMONEAUX SWD	Dry/Plugged	1,850	1,880	3,355	9,444	2.25
47529	L B SIMONEAUX SWD	Dry/Plugged	2,198	2,258	3,355	9,444	2.25
47529	L B SIMONEAUX SWD	Dry/Plugged	2,402	2,533	3,355	9,444	2.25
81236	WATERFORD OIL CO	Dry/Plugged	0	0	3,433	9,941	2.34
48599	LYDIA B SIMONEAUX ET AL SWD	Dry/Plugged	2,402	2,533	3,316	9,353	2.38
48599	LYDIA B SIMONEAUX ET AL SWD	Dry/Plugged	2,220	2,260	3,316	9,353	2.38
56972	S J SIMONEAUX	Orphan Well	0	0	3,510	9,971	2.40
167807	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,282	9,266	2.43
33280	S J SIMONEAUX	Orphan Well	0	0	3,574	9,960	2.43
138798	W H TALBOT	Dry/Plugged	0	0	3,312	9,247	2.43
211003	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,375	9,261	2.47
87029	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,296	9,302	2.52
69940	SIMONEAUX	Orphan Well	0	0	3,479	9,968	2.54
116758	ST CHARLES LAND TRUST	Dry/Plugged	0	0	3,280	9,926	2.59
115365	ST CHARLES LD CO A RA B	Dry/Plugged	0	0	3,359	9,966	2.59
178079	SIMONEAUX	Dry/Plugged	0	0	3,280	9,926	2.73
31709	ST CHARLES LAND CO	Dry/Plugged	0	0	3,359	9,966	2.73
137534	WM H TALBOT ETAL	Dry/Plugged	0	0	3,364	9,343	2.80
68317	SIMONEAUX	Dry/Plugged	0	0	3,280	9,926	2.81
251479	SELLERS HEIRS	Dry/Plugged	0	0	3,489	9,997	2.87
53428	SIMONEAUX	Dry/Plugged	0	0	3,359	9,966	2.89

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
108450	WILLIAM H TALBOT ET AL	Dry/Plugged	0	0	3,312	9,247	2.90
191264	ST CHARLES LAND CO A R/AA	Dry/Plugged	0	0	3,479	9,968	2.93
251714	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,479	9,968	2.93
114248	ST CHARLES LD CO A RA A	Dry/Plugged	0	0	3,479	9,968	2.98
56468	L B SIMONEAUX	Dry/Plugged	0	0	3,285	9,163	2.98
143907	IRELAND FEE	Dry/Plugged	0	0	3,310	9,254	2.99
113185	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	2.99
970048	RATHBORNE SWD	Dry/Plugged	2,250	2,270	3,314	9,143	3.01
970048	RATHBORNE SWD	Dry/Plugged	2,110	2,130	3,314	9,143	3.01
53063	WILLIAM H TALBOT	Dry/Plugged	0	0	3,276	9,135	3.03
108102	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	3.10
140976	M D SUMNERS ETAL	Dry/Plugged	0	0	3,580	9,822	3.11
164763	RATHBORNE LAND COMPANY INC	Dry/Plugged	0	0	3,272	9,203	3.11
150230	MITCHELL-NEELY FEE	Dry/Plugged	0	0	3,309	9,226	3.11
180305	L B SIMONEAUX	Dry/Plugged	0	0	3,325	9,458	3.13
107800	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	3.14
173741	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,422	9,549	3.20
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,980	2,170	3,222	9,882	3.21
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,120	2,170	3,222	9,882	3.21
121958	HUMBLE OIL & REFINING CO	Dry/Plugged	0	0	2,960	9,744	3.22
57829	JOSEPH RATHBORNE LAND & LBR CO	Dry/Plugged	0	0	3,251	9,093	3.24
95696	T B SELLERS	Dry/Plugged	0	0	3,489	9,997	3.27
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,750	1,780	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,865	1,880	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,750	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,865	2,022	3,222	9,882	3.29

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,792	1,842	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,972	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,770	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,135	2,820	3,222	9,882	3.29
173742	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,422	9,549	3.31
120976	HUMBLE O&R CO	Dry/Plugged	0	0	2,960	9,744	3.32
73869	RATHBORNE LAND & LUMBER	Dry/Plugged	0	0	3,248	9,109	3.32
21973	ST CHARLES LAND CO	Dry/Plugged	0	0	3,328	9,891	3.33
90455	SIMONEAUX	Dry/Plugged	0	0	3,222	9,882	3.35
142437	HANS C BLOCK FEE	Dry/Plugged	0	0	3,282	9,178	3.35
44831	SIMONEAUX	Dry/Plugged	0	0	3,328	9,891	3.39
20423	ST CHARLES LAND CO	Dry/Plugged	0	0	3,328	9,891	3.40
124302	HUMBLE OIL & REFG CO	Dry/Plugged	0	0	2,960	9,744	3.40
202150	M D SUMNERS	Dry/Plugged	0	0	3,497	9,719	3.40
60445	DELTA SEC CO INC	Dry/Plugged	0	0	3,353	10,013	3.40
116872	T B SELLERS	Dry/Plugged	0	0	3,547	10,057	3.41
116759	ST CHARLES LAND TRUST B	Dry/Plugged	0	0	2,812	9,617	3.48
50557	ST CHARLES LAND CO B	Dry/Plugged	0	0	2,939	9,622	3.49
971635	MITCHELL & NEELY SWD	Dry/Plugged	2,330	2,370	3,276	9,048	3.50
971635	MITCHELL & NEELY SWD	Dry/Plugged	2,500	2,540	3,276	9,048	3.50
73363	RATHBORNE LAND & LUMBER	Dry/Plugged	0	0	3,251	9,093	3.55
118175	DELTA SECURITIES	Dry/Plugged	0	0	2,845	9,665	3.57
172018	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,451	9,518	3.58
180436	SIMONEAUX	Dry/Plugged	0	0	2,812	9,617	3.60
152640	MITCHELL & NEELY	Dry/Plugged	0	0	3,276	9,048	3.61
139476	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,217	9,091	3.62
117375	C E GHEENS	Dry/Plugged	0	0	2,938	9,703	3.62
49051	IRELAND FEE	Dry/Plugged	0	0	3,497	9,719	3.65
48783	JOESPH RATHBORNE LD LBR CO	Dry/Plugged	0	0	3,242	9,181	3.65
115907	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.68
970034	C E GHEENS SWD	Active Injector	1,892	1,920	3,419		3.68

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
970034	C E GHEENS SWD	Active Injector	1,949	1,969	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,700	1,710	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,190	1,276	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,400	1,490	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,892	1,969	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,236	1,276	3,419		3.68
78858	JOSEPH RATHBORNE LAND CO INC	Orphan Well	0	0	3,223	9,018	3.68
154381	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.71
105439	DELTA SEC CO INC	Dry/Plugged	0	0	2,845	9,665	3.73
195630	C E GHEENS	Shut-In/TA	0	0	2,962		3.74
23323	C E GHEENS SWD	Dry/Plugged	1,350	1,400	2,938	9,703	3.74
217805	PAR 9500 RD SU;WIDENER	Dry/Plugged	0	0	3,304	9,259	3.75
62946	DELTA SEC B	Dry/Plugged	0	0	2,813	9,688	3.77
109671	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.81
68131	GHEENS SWD SYSTEMS	Dry/Plugged	1,880	1,930	2,938	9,703	3.86
84549	C E GHEENS	Dry/Plugged	0	0	2,938	9,703	3.86
68131	GHEENS SWD SYSTEMS	Dry/Plugged	1,700	1,710	2,938	9,703	3.86
24099	GHEENS DIST SWDS	Dry/Plugged	1,945	2,010	2,962		3.86
162352	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,214	9,040	3.89
113797	GHEENS SWD	Dry/Plugged	1,670	1,700	2,938	9,703	3.89
113797	GHEENS SWD	Dry/Plugged	1,990	2,030	2,938	9,703	3.89
199967	VUA;JOS RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,214	9,040	3.90
134633	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,329	9,442	3.90
207262	C E GHEENS	Dry/Plugged	0	0	3,419		3.93
174198	MITCHELL & NEELEY	Dry/Plugged	0	0	3,242	8,960	3.94
152158	SL 6184	Dry/Plugged	0	0	3,273	9,261	3.95
107747	WATERFORD	Dry/Plugged	0	0	2,813	9,688	3.95
38575	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.95
157205	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,210	9,039	3.97
251822	EMC FEE A	Dry/Plugged	0	0	2,813	9,688	3.98
228861	EXXONMOBIL FEE	Dry/Plugged	0	0	3,226	9,856	3.99
27512	C E GHEENS	Dry/Plugged	0	0	3,100		4.01
202777	ST CHARLES PH SCHL BD	Dry/Plugged	0	0	3,316	9,379	4.03
40494	G E GHEENS	Dry/Plugged	0	0	2,707	9,217	4.06
34610	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,327	9,953	4.09
88410	WATERFORD OIL CO B	Dry/Plugged	0	0	3,448	10,034	4.11
228795	EXXONMOBIL FEE	Dry/Plugged	0	0	3,327	9,953	4.14

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
92455	W H TALBOT ETAL	Dry/Plugged	0	0	3,223	9,018	4.15
165395	IRELAND FEE	Dry/Plugged	0	0	3,165	9,054	4.17
68316	GHEENS SWD	Dry/Plugged	1,900	1,950	2,646	9,470	4.17
68316	GHEENS SWD	Dry/Plugged	1,446	1,496	2,646	9,470	4.17
186151	JOS RATHBORNE LAND CO INC A	Dry/Plugged	0	0	3,214	9,040	4.18
140130	IRELAND FEE	Dry/Plugged	0	0	3,462	9,519	4.18
108028	RATHBORNE LD & LBR CO INC	Dry/Plugged	0	0	3,214	9,040	4.20
207741	C E GHEENS	Dry/Plugged	0	0	3,100		4.24
115161	C E GHEENS	Dry/Plugged	0	0	2,638		4.25
40970	C E GHEENS	Dry/Plugged	0	0	3,100		4.26
96089	J RATHBORNE L & L CO INC	Dry/Plugged	0	0	3,232	9,155	4.28
143281	C E GHEENS	Dry/Plugged	0	0	2,646	9,470	4.31
116132	C E GHEENS	Dry/Plugged	0	0	2,836		4.35
59256	WATERFORD OIL CO B	Dry/Plugged	0	0	3,388	10,108	4.36
72624	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	2,420	2,710	3,264	9,191	4.44
72624	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	2,640	2,710	3,264	9,191	4.44
72624	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	3,028	3,116	3,264	9,191	4.44
72624	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	2,850	2,880	3,264	9,191	4.44
35837	C E GHEENS	Dry/Plugged	0	0	2,638		4.44
83940	JOS RATHBORNE LAND & LUMBER CO	Dry/Plugged	0	0	3,189	8,949	4.46
33398	GHEENS SWD	Dry/Plugged	1,800	1,840	2,646	9,470	4.48
116865	GHEENS SWD	Dry/Plugged	1,830	1,870	2,646	9,470	4.49
116865	GHEENS SWD	Dry/Plugged	1,626	1,665	2,646	9,470	4.49
116865	GHEENS SWD	Dry/Plugged	1,475	1,500	2,646	9,470	4.49
116865	GHEENS SWD	Dry/Plugged	1,818	1,858	2,646	9,470	4.49
117650	GHEENS SWD	Dry/Plugged	1,460	1,486	2,646	9,470	4.49
117650	GHEENS SWD	Dry/Plugged	1,930	1,970	2,646	9,470	4.49
117650	GHEENS SWD	Dry/Plugged	1,582	1,622	2,646	9,470	4.49
154382	C E GHEENS	Dry/Plugged	0	0	2,638		4.50
145893	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,264	9,191	4.51
143407	C E GHEENS	Dry/Plugged	0	0	2,638		4.52
85670	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,162	9,781	4.52
143908	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.56
144626	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	1,844	1,960	3,264	9,191	4.56
38223	C E GHEENS	Dry/Plugged	0	0	2,836		4.57
147388	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.59
207279	MITCHELL & NEELY	Dry/Plugged	0	0	3,169	8,805	4.63
84631	WATERFORD	Dry/Plugged	0	0	3,255	9,794	4.70
69431	T C DUFRENE	Dry/Plugged	0	0	3,044	9,027	4.71
38003	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	1,850	1,960	3,277	9,243	4.74

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
38003	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	2,380	2,550	3,277	9,243	4.74
56117	GHEENS DIST SWDS	Dry/Plugged	1,688	1,980	2,596	9,413	4.74
53320	DELTA SEC CO INC	Dry/Plugged	0	0	3,255	9,794	4.74
142325	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.75
99536	JOS RATHBORNE LD CO INC	Dry/Plugged	0	0	3,186	8,945	4.76
30704	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,541	10,087	4.79
213352	EXXON FEE	Dry/Plugged	0	0	3,423	10,011	4.82
32297	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,423	10,011	4.83
70738	DELTA SEC CO INC A	Dry/Plugged	0	0	3,312	9,867	4.83
971416	RATHBORNE LBR & SHL WTR DSP	Dry/Plugged	2,372	2,392	3,259	9,213	4.84
83422	WATERFORD OIL CO	Dry/Plugged	0	0	3,183	9,699	4.86
199376	RATHBORNE LAND CO	Dry/Plugged	0	0	3,215	9,093	4.86
143461	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.86
31755	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,423	10,011	4.87
51640	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	4.88
235980	CIB O RA SUA;EXXONMOBIL FEE	Dry/Plugged	0	0	3,423	10,011	4.90
72631	WATERFORD OIL CO	Dry/Plugged	0	0	3,399	10,087	4.91
28543	PETER REISCH	Dry/Plugged	0	0	2,926	8,916	4.92
166914	EXXON FEE	Dry/Plugged	0	0	2,698	9,541	4.92
41463	C E CHEENS	Dry/Plugged	0	0	2,596	9,413	4.94
72001	DELTA SECURITIES CO INC A	Dry/Plugged	0	0	3,312	9,867	4.97
28616	C E GHEENS	Dry/Plugged	0	0	2,725		4.97
117891	RATHBORNE LND & LBR CO	Dry/Plugged	0	0	3,164	8,888	4.99
152117	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,277	9,243	5.00
55613	DELTA S C CO INC	Dry/Plugged	0	0	3,225	9,679	5.08
47175	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.09
97884	JOS RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,167	8,869	5.09
50669	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.11
48648	DELTA SEC CO INC	Dry/Plugged	0	0	3,160	9,527	5.12
50416	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,754	9,638	5.17
123250	10000 RB SUB; CLAUDE AUTIN	Dry/Plugged	0	0	3,400	9,393	5.18
54825	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.19
137241	IRELAND FEE	Dry/Plugged	0	0	2,989	8,824	5.19
43270	DELTA SEC CO INC	Dry/Plugged	0	0	3,199	9,781	5.19
44414	DELTA SEC CO INC	Dry/Plugged	0	0	3,312	9,867	5.19
142842	IRELAND FEE	Dry/Plugged	0	0	3,538		5.20
50170	DELTA SEC CO INC	Dry/Plugged	2,642	2,646	3,225	9,679	5.20
47827	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.23
160295	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,097	9,024	5.23
61848	W H TALBOT ETAL	Dry/Plugged	0	0	3,154	8,830	5.24

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
57707	WATERFORD OIL COMPANY	Dry/Plugged	0	0	2,951	9,710	5.24
64758	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,238	9,612	5.25
142607	DELTA SEC CO INC	Shut-In/TA	2,308	2,318	3,160	9,527	5.28
30232	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,225	9,679	5.28
146352	THOMAS GREEN	Dry/Plugged	0	0	3,400	9,393	5.29
27720	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.33
51349	DELTA SEC CO INC	Dry/Plugged	0	0	3,160	9,527	5.36
124076	DELTA SECURITIES	Dry/Plugged	0	0	3,199	9,781	5.36
228543	DELTA SEC CO INC	Dry/Plugged	0	0	3,199	9,781	5.39
38046	DELTA SEC CO INC	Dry/Plugged	3,010	3,015	3,160	9,527	5.48
970126	SUNSET R & P SWD	Dry/Plugged	1,613	1,685	3,097	9,024	5.48
85381	JOESPH RATHBORNE LD LBR CO INC	Dry/Plugged	0	0	3,210	9,298	5.48
32929	DELTA SEC CO INC SWD	Dry/Plugged	1,036	1,066	3,199	9,781	5.49
33722	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.50
37319	DELTA SEC CO INC SWD	Dry/Plugged	1,068	1,196	3,132	9,506	5.53
55112	DELTA SEC CO INC SWD	Active Injector	2,786	2,820	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	0	0	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	2,890	2,920	3,199	9,781	5.55
27649	DELTA SEC CO INC SWD	Dry/Plugged	1,100	1,300	3,132	9,506	5.58
42560	DELTA SEC CO INC	Dry/Plugged	3,024	3,032	3,160	9,527	5.59
72608	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.69
53706	DELTA SEC CO INC	Dry/Plugged	0	0	3,132	9,506	5.74
42933	DELTA SEC CO INC	Dry/Plugged	2,700	2,708	3,132	9,506	5.75
245470	DELTA SEC CO INC	Shut-In/TA	2,705	2,709	3,108	9,220	5.75
210859	THE LEON GODCHAUX CO LTD	Dry/Plugged	0	0	3,410	9,403	5.76
153595	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,108	9,220	5.78
73215	DELTA SEC CO INC / A	Dry/Plugged	0	0	3,093	9,477	5.82
28441	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	5.89
27882	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,012	9,701	5.90
23759	MATHEWS OLIVIERS	Dry/Plugged	0	0	3,045	8,734	5.90
28032	ELLINGTON	Dry/Plugged	0	0	3,082	8,570	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	2,952	2,960	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	2,952	2,970	3,097	8,938	5.92
46132	DELTA SEC CO INC	Dry/Plugged	0	0	3,012	9,701	5.95
122383	J B PEYREGNE	Dry/Plugged	0	0	3,355	9,287	5.95

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
27584	MRS PAUL PEYREGNE	Dry/Plugged	0	0	3,355	9,287	6.03
240448	BOWIE LUMBER CO	Dry/Plugged	0	0	3,410	9,403	6.11
71411	DELTA SECURITIES CO INC A	Dry/Plugged	0	0	3,012	9,701	6.11
25010	A P PEYREGNE	Dry/Plugged	0	0	3,438		6.14
48479	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	6.14
970125	PROVIDENCE LAND CORP SWD	Dry/Plugged	2,920	2,940	3,157	9,057	6.16
140649	A T PEYREGNE ET AL	Dry/Plugged	0	0	3,438		6.16
138588	GORDON REESE	Dry/Plugged	0	0	3,109	8,669	6.18
41571	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	6.19
83040	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,108	9,220	6.19
970127	PAR 9900 NAG SWD	Dry/Plugged	1,530	1,585	3,008	8,780	6.24
970128	LL&E SWD	Active Injector	1,970	2,086	3,008	8,780	6.24
970128	LL&E SWD	Active Injector	2,246	2,286	3,008	8,780	6.24
970128	LL&E SWD	Active Injector	2,266	2,286	3,008	8,780	6.24
970139	LL&E SWD	Dry/Plugged	2,300	2,362	3,008	8,780	6.25
970139	LL&E SWD	Dry/Plugged	2,695	2,795	3,008	8,780	6.25
970139	LL&E SWD	Dry/Plugged	2,036	2,362	3,008	8,780	6.25
970139	LL&E SWD	Dry/Plugged	2,532	2,646	3,008	8,780	6.25
27543	LL&E SWD	Active Injector	2,960	2,980	3,008	8,780	6.27
27543	LL&E SWD	Active Injector	2,920	3,000	3,008	8,780	6.27
30110	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,982	9,365	6.31
98328	WATERFORD OIL CO	Dry/Plugged	0	0	2,899	9,687	6.37
30546	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,982	9,365	6.40
51054	DELTA SEC CO INC	Dry/Plugged	0	0	3,023	8,951	6.42
48770	DELTA SEC CO INC	Dry/Plugged	0	0	2,889	9,403	6.46
29339	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,023	8,951	6.47
76153	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,023	8,951	6.48
53061	DELTA SEC CO INC	Dry/Plugged	0	0	2,889	9,403	6.53
84624	WATERFORD OIL CO	Dry/Plugged	0	0	3,094	9,861	6.53
169297	EXXON FEE	Dry/Plugged	0	0	3,027	8,850	6.58
78280	WATERFORD OIL COMPANY	Dry/Plugged	0	0	2,899	9,687	6.66
80424	WATERFORD OIL CO	Dry/Plugged	0	0	2,889	9,403	6.70
196676	SL 11680	Dry/Plugged	0	0	3,548	10,019	7.43
62991	STATE LEASE 2827	Dry/Plugged	0	0	3,518	9,856	7.83
58976	STATE LEASE 2828	Dry/Plugged	0	0	3,518	9,856	8.29
62800	STATE LEASE 2828	Dry/Plugged	0	0	3,518	9,856	8.29

*TA – temporarily abandoned

1.11.6 Nearby Artificial Penetrations with Perforations in the Injection Zone

The perforated intervals within 5 mi of the proposed area boundary and within the injection zone are listed in Table 1-21. The wells identified in this zone consist of 11 active injector wells, 26 active oil or gas wells, 163 dry hole or plugged wells, 4 orphan wells, 88 shut-in or temporarily abandoned wells, and 1 well that was unable to be located.

Table 1-21 – Oil and gas wells within 5 mi of the area boundary with perforations within the injection zone.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	6,590	6,610	3,372	9,417	2.02
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,210	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,160	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,054	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,996	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,710	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,040	5,230	3,282	9,266	2.22
27947	BDA BOL 5 SU	Dry/Plugged	9,787	9,798	3,489	9,997	2.87
27947	BDA BOL 5 SU	Dry/Plugged	9,806	9,814	3,489	9,997	2.87
114087	BDA 5000' RA SU; ST CHARLES LD	Dry/Plugged	5,006	5,010	3,479	9,968	2.92
117636	BDA 5000' RA SU; ST CHARLES LD	Dry/Plugged	5,002	5,007	3,328	9,891	2.94
27611	BOLIVINA 5 SUA;ST CHAS LD	Dry/Plugged	9,750	9,760	3,489	9,997	3.01
113789	BDA 5000 RA SU;ST CHAS LD CO A	Active Oil/Gas	4,983	4,995	3,328	9,891	3.07
113789	BDA 5000 RA SU;ST CHAS LD CO A	Active Oil/Gas	4,998	5,002	3,328	9,891	3.07
205815	BDA 5000 RA SU;ST CHARLES B	Shut-In/TA	5,015	5,021	3,328	9,891	3.08
113302	ST CHARLES LAND CO A RAB	Active Oil/Gas	5,446	5,454	3,328	9,891	3.09
119711	BDA BOL 5 SU; SL 348	Dry/Plugged	9,765	9,775	3,489	9,997	3.13
119711	BDA BOL 5 SU; SL 348	Dry/Plugged	9,818	9,830	3,489	9,997	3.13
119711	BDA BOL 5 SU; SL 348	Dry/Plugged	9,764	9,830	3,489	9,997	3.13
113798	ST CHARLES LAND CO A RAB	Dry/Plugged	5,432	5,436	3,328	9,891	3.13
114215	BDA 5000' RA SU; ST CHARLES LD	Dry/Plugged	4,999	5,003	3,328	9,891	3.13
114215	BDA 5000' RA SU; ST CHARLES LD	Dry/Plugged	5,000	5,004	3,328	9,891	3.13
27261	ST CHARLES LAND CO	Dry/Plugged	5,096	5,100	3,489	9,997	3.14

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
101496	DELTA SECURITIES CO INC	Dry/Plugged	4,367	4,371	2,960	9,744	3.15
107407	DELTA SEC CO INC	Dry/Plugged	5,339	5,343	3,222	9,882	3.15
108040	DELTA SECURITIES CO INC	Dry/Plugged	5,147	5,151	3,222	9,882	3.15
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,460	5,538	3,222	9,882	3.18
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,228	5,538	3,222	9,882	3.18
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,460	5,528	3,222	9,882	3.18
108601	DELTA SECURITIES CO INC	Active Oil/Gas	5,075	5,084	3,222	9,882	3.19
27233	SL 348	Dry/Plugged	5,424	5,432	3,489	9,997	3.20
973213	J RATHBORNE LD & LBR CO SWD	Dry/Plugged	3,934	3,954	3,274	9,072	3.20
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	4,461	4,471	3,222	9,882	3.21
45469	S J SIMONEAUX	Orphan Well	9,608	9,614	3,328	9,891	3.21
106968	DELTA SECURITIES CO INC	Dry/Plugged	5,535	5,540	3,222	9,882	3.22
107817	DELTA SECURITIES CO INC	Dry/Plugged	4,871	4,876	3,222	9,882	3.22
104652	DELTA SECURITIES CO INC	Shut-In/TA	4,408	4,418	3,222	9,882	3.22
105573	DELTA SECURITIES CO INC	Active Oil/Gas	5,278	5,284	3,222	9,882	3.22
104652	DELTA SECURITIES CO INC	Shut-In/TA	5,329	5,336	3,222	9,882	3.22
101703	DELTA SECURITIES CO INC	Dry/Plugged	5,331	5,336	3,222	9,882	3.23
100911	C RA SUA;DELTA SECURITIES	Dry/Plugged	4,826	4,832	3,222	9,882	3.23
100911	C RA SUA;DELTA SECURITIES	Dry/Plugged	5,230	5,237	3,222	9,882	3.23
62582	J RATHBORNE LD & LBR SWD	Dry/Plugged	3,617	3,645	3,274	9,072	3.23
62582	J RATHBORNE LD & LBR SWD	Dry/Plugged	3,648	3,702	3,274	9,072	3.23
62582	J RATHBORNE LD & LBR SWD	Dry/Plugged	3,486	3,702	3,274	9,072	3.23
62582	J RATHBORNE LD & LBR SWD	Dry/Plugged	3,527	3,702	3,274	9,072	3.23
62582	J RATHBORNE LD & LBR SWD	Dry/Plugged	3,617	3,702	3,274	9,072	3.23
107966	D RC SUA;DELTA SECURITIES	Shut-In/TA	4,864	4,874	3,222	9,882	3.25
107966	D RC SUA;DELTA SECURITIES	Shut-In/TA	5,516	5,524	3,222	9,882	3.25
117203	TT SUA; SELLERS S L 348	Dry/Plugged	4,779	4,790	3,359	9,951	3.27
115563	B D A SELLERS S U	Dry/Plugged	5,426	5,429	3,359	9,951	3.27
43470	BDA 5500' RBSU;DELTA SEC CO	Dry/Plugged	5,532	5,538	3,222	9,882	3.27
124125	HUMBLE OIL & REFINING CO	Dry/Plugged	4,086	4,089	2,960	9,744	3.28
124125	HUMBLE OIL & REFINING CO	Dry/Plugged	4,522	4,524	2,960	9,744	3.28
123285	HUMBLE OIL & REFINING CO	Dry/Plugged	4,086	4,089	2,960	9,744	3.28
123285	HUMBLE OIL & REFINING CO	Dry/Plugged	4,553	4,555	2,960	9,744	3.28
41534	S J SIMONEAUX	Dry/Plugged	9,630	9,656	3,222	9,882	3.28
192950	DELTA SECURITIES CO INC	Shut-In/TA	6,236	6,244	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,766	5,784	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,508	5,520	3,222	9,882	3.29

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,306	5,316	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,286	5,294	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,250	5,258	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	6,156	6,180	3,222	9,882	3.29
112859	SL 348	Dry/Plugged	5,411	5,414	3,359	9,951	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	5,285	5,294	3,222	9,882	3.29
208420	X RA SUA;SL 348	Shut-In/TA	7,210	7,217	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	7,160	7,166	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	5,585	5,695	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	5,128	5,130	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	5,116	5,131	3,359	9,951	3.30
28215	T B SELLERS	Dry/Plugged	3,755	3,761	3,547	10,057	3.31
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,520	5,526	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,300	5,306	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,331	5,334	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,196	5,204	3,222	9,882	3.32
43236	4100 RA SUA;SIMONEAUX	Orphan Well	4,112	4,118	3,328	9,891	3.35
43236	4100 RA SUA;SIMONEAUX	Orphan Well	6,284	6,290	3,328	9,891	3.35
43236	4100 RA SUA;SIMONEAUX	Orphan Well	4,920	4,926	3,328	9,891	3.35
43721	SIMONEAUX	Dry/Plugged	6,450	6,456	3,328	9,891	3.35
52926	BDA 5500 SU;DELTA SECURITIES	Active Oil/Gas	5,456	5,462	3,222	9,882	3.37
21214	ST CHARLES LAND CO	Dry/Plugged	8,888	8,897	3,328	9,891	3.38
44983	S J SIMONEAUX	Orphan Well	4,896	4,904	3,328	9,891	3.38
26731	21 RA SUA;SELLERS	Dry/Plugged	4,057	4,069	3,359	9,951	3.39
26731	21 RA SUA;SELLERS	Dry/Plugged	5,424	5,438	3,359	9,951	3.39
26731	21 RA SUA;SELLERS	Dry/Plugged	5,031	5,034	3,359	9,951	3.39
248482	DELTA SECURITIES CO INC	Active Oil/Gas	4,581	4,590	3,222	9,882	3.39
248482	DELTA SECURITIES CO INC	Active Oil/Gas	4,581	4,587	3,222	9,882	3.39
52661	BDA 5500 SU	Dry/Plugged	5,477	5,483	3,222	9,882	3.40
44531	BAYOU DES ALLEMANDS STATE	Dry/Plugged	6,406	6,438	3,328	9,891	3.40
51263	BDA 5500 SU; SL 348	Dry/Plugged	5,478	5,495	3,222	9,882	3.41
20896	BOLIVINA 5 SUC; ST.LSE. #348	Dry/Plugged	9,387	9,474	3,359	9,951	3.41

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
124301	HUMBLE OIL & REFG CO	Dry/Plugged	5,334	5,335	2,960	9,744	3.43
19717	S.L. 348	Dry/Plugged	6,818	6,824	3,328	9,891	3.45
60108	WATERFORD OIL COMPANY A	Orphan Well	5,352	5,356	2,863	9,716	3.47
25009	GHEENS	Dry/Plugged	9,884	9,890	3,359	9,951	3.53
40116	BDA 5500 SU;SL 348	Dry/Plugged	5,495	5,505	2,939	9,622	3.54
112882	11 RA VUA;SL 348	Dry/Plugged	8,220	8,234	2,938	9,703	3.57
114216	G RA VUA;SL 348	Dry/Plugged	6,921	6,929	2,938	9,703	3.57
20937	GHEENS	Dry/Plugged	7,239	7,254	2,938	9,703	3.59
75559	STATE GHEENS UNIT	Dry/Plugged	8,274	8,280	3,359	9,951	3.60
77308	STATE GHEENS UNIT	Dry/Plugged	8,213	8,221	3,359	9,951	3.60
132172	CRIST I 40 SU B; S.L. 348	Dry/Plugged	9,039	9,085	2,938	9,703	3.61
132172	CRIST I 40 SU B; S.L. 348	Dry/Plugged	8,997	9,001	2,938	9,703	3.61
114894	M-1 RB VUA; SL 348	Shut-In/TA	6,588	6,596	2,938	9,703	3.66
113157	LWR G-1 VUA; C E GHEENS	Dry/Plugged	7,096	7,104	2,938	9,703	3.66
111897	B N 1 RB VUA; C E GHEENS	Dry/Plugged	6,900	6,930	2,938	9,703	3.66
39074	C. E. GHEENS	Dry/Plugged	9,501	9,541	2,939	9,622	3.67
207261	C E GHEENS	Shut-In/TA	7,672	7,682	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	6,152	6,157	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	7,703	7,720	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	6,136	6,142	2,938	9,703	3.68
114898	EXXON COMMUNITY	Dry/Plugged	6,279	6,292	2,938	9,703	3.68
115806	U X1 RA VUA; SL 348	Shut-In/TA	5,978	5,982	2,938	9,703	3.68
115806	U X1 RA VUA; SL 348	Shut-In/TA	5,938	5,960	2,938	9,703	3.68
114907	TT RB SUA;GHEENS	Dry/Plugged	5,488	5,493	2,938	9,703	3.69
114907	TT RB SUA;GHEENS	Dry/Plugged	6,952	6,958	2,938	9,703	3.69
114907	TT RB SUA;GHEENS	Dry/Plugged	7,298	7,308	2,938	9,703	3.69
114419	7200 VUA; C E GHEENS	Dry/Plugged	7,174	7,184	2,938	9,703	3.69
91893	C E GHEENS	Dry/Plugged	7,972	7,987	2,939	9,622	3.69
40821	GHEENS C E	Dry/Plugged	7,860	7,866	2,939	9,622	3.69
75500	BDA TEX M-1 1 RA SU;GHEENS	Dry/Plugged	7,688	7,692	2,938	9,703	3.69
75500	BDA TEX M-1 1 RA SU;GHEENS	Dry/Plugged	7,731	7,741	2,938	9,703	3.69
76583	C E GHEENS	Dry/Plugged	7,705	7,710	2,938	9,703	3.69
207742	BIG N 1 RA SUA; SL 348	Shut-In/TA	6,869	6,892	2,938	9,703	3.70
207742	BIG N 1 RA SUA; SL 348	Shut-In/TA	6,848	6,866	2,938	9,703	3.70
51350	C E GHEENS	Dry/Plugged	6,809	6,813	3,359	9,951	3.70
51350	C E GHEENS	Dry/Plugged	3,494	3,498	3,359	9,951	3.70
142732	BIG N 1 RB SUA;C E GHEENS	Shut-In/TA	6,920	6,946	2,938	9,703	3.72
142732	BIG N 1 RB SUA;C E GHEENS	Shut-In/TA	7,293	7,300	2,938	9,703	3.72
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,244	7,268	2,938	9,703	3.75

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,334	7,344	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,270	7,283	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,416	7,425	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,244	7,257	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,609	7,646	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,826	7,840	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,718	7,732	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,736	7,744	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,096	7,110	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,333	7,339	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,624	7,641	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,555	7,557	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,618	7,622	2,938	9,703	3.75
22809	GHEENS	Dry/Plugged	7,242	7,258	2,938	9,703	3.75
111953	BDA G2 RB SU;GHEENS	Dry/Plugged	7,935	7,962	2,938	9,703	3.76
113495	C E GHEENS	Dry/Plugged	7,802	7,808	2,938	9,703	3.76
37917	BDA G-2 RC SU;GHEENS	Dry/Plugged	8,038	8,047	2,939	9,622	3.81
83918	GHEENS C.E.	Dry/Plugged	7,915	7,920	2,939	9,622	3.81
131785	C E GHEENS A	Dry/Plugged	7,854	7,862	2,938	9,703	3.81
131586	C. E. GHEENS A	Dry/Plugged	8,533	8,540	2,938	9,703	3.81
124074	GHEENS C E	Dry/Plugged	8,066	8,069	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	7,876	7,888	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	8,053	8,061	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	8,030	8,053	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	7,958	7,986	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	7,986	8,030	2,939	9,622	3.87
195841	C E GHEENS	Shut-In/TA	7,691	7,708	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,675	7,688	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,770	7,802	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,808	7,816	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,655	7,660	2,938	9,703	3.88
208093	C E GHEENS	Shut-In/TA	7,223	7,227	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,530	7,571	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,263	7,265	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,197	7,214	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,638	7,646	2,938	9,703	3.91

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
208094	C E GHEENS	Shut-In/TA	7,993	8,004	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	7,262	7,270	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	8,121	8,130	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	7,880	7,952	2,938	9,703	3.92
124718	GHEENS C E	Dry/Plugged	7,606	7,655	2,938	9,703	3.96
124075	C E GHEENS	Dry/Plugged	7,754	7,762	2,938	9,703	3.96
84641	C E GHEENS	Dry/Plugged	7,930	7,935	2,938	9,703	3.96
41160	BDA D-2 RB SU;GHEENS	Dry/Plugged	7,930	7,935	2,938	9,703	3.96
115455	BDA G-2 RD SU;GHEENS	Dry/Plugged	8,114	8,120	2,939	9,622	3.99
116471	GHEENS C E	Dry/Plugged	7,874	7,883	2,939	9,622	3.99
115455	BDA G-2 RD SU;GHEENS	Dry/Plugged	8,092	8,102	2,939	9,622	3.99
115455	BDA G-2 RD SU;GHEENS	Dry/Plugged	8,011	8,013	2,939	9,622	3.99
90253	SD 3 PR; C. E. GHEENS	Dry/Plugged	7,757	7,780	2,938	9,703	4.00
89320	BDA 3 RF SU;GHEENS	Dry/Plugged	7,751	7,765	2,938	9,703	4.00
89320	BDA 3 RF SU;GHEENS	Dry/Plugged	7,830	7,838	2,938	9,703	4.00
204744	C E GHEENS	Shut-In/TA	4,884	4,896	2,938	9,703	4.00
204744	C E GHEENS	Shut-In/TA	7,904	7,912	2,938	9,703	4.00
204744	C E GHEENS	Shut-In/TA	8,126	8,148	2,938	9,703	4.00
35998	C E GHEENS	Dry/Plugged	8,269	8,274	2,707	9,217	4.04
142125	PAR 8 RA SU	Dry/Plugged	9,633	9,656	3,511	9,686	4.04
205601	C E GHEENS	Shut-In/TA	7,891	7,917	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	8,042	8,062	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,825	7,830	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	8,000	8,035	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,749	7,758	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,726	7,736	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,552	7,561	2,646	9,470	4.05
73484	GHEENS C E	Dry/Plugged	7,804	7,852	2,646	9,470	4.09
74688	C E GHEENS	Dry/Plugged	7,935	7,962	2,646	9,470	4.09
132171	C E GHEENS	Dry/Plugged	8,074	8,080	2,646	9,470	4.09
132171	C E GHEENS	Dry/Plugged	8,004	8,024	2,646	9,470	4.09
132171	C E GHEENS	Dry/Plugged	7,934	7,942	2,646	9,470	4.09
132171	C E GHEENS	Dry/Plugged	8,044	8,052	2,646	9,470	4.09
122633	GHEENS C.E.	Dry/Plugged	7,596	7,610	2,646	9,470	4.10
29257	C E GHEENS	Dry/Plugged	7,274	7,281	2,646	9,470	4.11
207739	C E GHEENS	Dry/Plugged	8,118	8,145	2,646	9,470	4.13
111487	BDA 3 RE SU;GHEENS	Dry/Plugged	7,762	7,765	2,646	9,470	4.16
111017	BDA G-3 RC SU;GHEENS	Dry/Plugged	7,401	7,438	2,646	9,470	4.16
111017	BDA G-3 RC SU;GHEENS	Dry/Plugged	7,451	7,455	2,646	9,470	4.16
69439	C E GHEENS	Dry/Plugged	7,388	7,403	2,646	9,470	4.17
68316	GHEENS SWD	Dry/Plugged	7,347	7,356	2,646	9,470	4.17

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
84581	C E GHEENS	Dry/Plugged	7,803	7,814	2,646	9,470	4.17
35198	C E GHEENS	Dry/Plugged	7,941	7,953	2,646	9,470	4.17
142039	PAR 8 RA SU;IRELAND	Dry/Plugged	9,604	9,666	3,511	9,686	4.19
142039	PAR 8 RA SU;IRELAND	Dry/Plugged	9,614	9,632	3,511	9,686	4.19
132072	GHEENS C E	Dry/Plugged	8,313	8,318	2,646	9,470	4.19
131492	GHEENS C E	Dry/Plugged	8,341	8,349	2,646	9,470	4.19
132072	GHEENS C E	Dry/Plugged	8,290	8,294	2,646	9,470	4.19
132072	GHEENS C E	Dry/Plugged	8,301	8,330	2,646	9,470	4.19
132072	GHEENS C E	Dry/Plugged	8,298	8,307	2,646	9,470	4.19
143184	BDA G 2 RE SU;GHEENS	Dry/Plugged	7,021	7,038	2,646	9,470	4.21
36868	C E GHEENS	Dry/Plugged	8,222	8,227	2,707	9,217	4.22
37708	BDA G 3 RC SU;GHEENS	Dry/Plugged	7,388	7,393	2,646	9,470	4.23
37708	BDA G 3 RC SU;GHEENS	Dry/Plugged	7,376	7,404	2,646	9,470	4.23
37708	BDA G 3 RC SU;GHEENS	Dry/Plugged	7,882	7,895	2,646	9,470	4.23
84582	C E GHEENS	Dry/Plugged	7,468	7,474	2,646	9,470	4.23
37708	BDA G 3 RC SU;GHEENS	Dry/Plugged	7,423	7,433	2,646	9,470	4.23
205600	C E GHEENS	Dry/Plugged	7,352	7,356	2,646	9,470	4.24
205600	C E GHEENS	Dry/Plugged	7,386	7,420	2,646	9,470	4.24
205600	C E GHEENS	Dry/Plugged	7,243	7,249	2,646	9,470	4.24
111934	GHEENS C E	Dry/Plugged	7,381	7,387	2,646	9,470	4.25
110914	GHEENS C.E.	Dry/Plugged	7,445	7,465	2,646	9,470	4.25
124719	BDA D-2 RC SU;GHEENS	Dry/Plugged	8,158	8,166	2,646	9,470	4.27
108097	C E GHEENS	Dry/Plugged	7,875	7,889	2,646	9,470	4.29
107239	BDA T M-1 #2 RA SU;GHEENS	Dry/Plugged	7,754	7,795	2,646	9,470	4.29
205767	C E GHEENS	Shut-In/TA	7,660	7,672	2,646	9,470	4.29
205767	C E GHEENS	Shut-In/TA	7,388	7,398	2,646	9,470	4.29
205767	C E GHEENS	Shut-In/TA	7,728	7,770	2,646	9,470	4.29
86867	C E GHEENS	Active Oil/Gas	7,766	7,770	2,646	9,470	4.30
90496	C E GHEENS	Dry/Plugged	7,930	7,938	2,646	9,470	4.31
92442	BDA 14 B RB SU;C E GHEENS	Dry/Plugged	7,878	7,881	2,646	9,470	4.31
96403	BDA 14-B RC SU;GHEENS	Dry/Plugged	8,296	8,300	2,646	9,470	4.35
34695	BDA 14-B RC SU;GHEENS	Dry/Plugged	8,167	8,174	2,646	9,470	4.35
85523	C E GHEENS	Shut-In/TA	8,039	8,045	2,646	9,470	4.35
85523	C E GHEENS	Shut-In/TA	7,904	7,912	2,646	9,470	4.35
85523	C E GHEENS	Shut-In/TA	7,896	7,912	2,646	9,470	4.35
197118	C E GHEENS	Shut-In/TA	7,566	7,577	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,674	7,705	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,720	7,728	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,026	7,042	2,646	9,470	4.38

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
197118	C E GHEENS	Shut-In/TA	8,262	8,272	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,142	8,164	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,212	8,217	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,176	8,192	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,977	7,988	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,944	7,968	2,646	9,470	4.38
90519	C E GHEENS	Active Oil/Gas	7,758	7,765	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,402	7,410	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,420	7,422	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,613	7,628	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,890	7,908	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,934	7,942	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	8,212	8,225	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	8,212	8,292	2,646	9,470	4.40
125941	BDA 14-B RA SU;GHEENS	Shut-In/TA	7,896	7,906	2,646	9,470	4.40
125419	C E GHEENS	Active Oil/Gas	8,057	8,087	2,646	9,470	4.40
111486	GHEENS C E	Dry/Plugged	8,012	8,016	2,646	9,470	4.41
109013	BDA 14-B RB SU;GHEENS	Dry/Plugged	8,147	8,171	2,646	9,470	4.41
207203	C E GHEENS SWD	Active Injector	2,727	2,747	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	3,909	3,969	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	4,160	4,270	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	8,105	8,116	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	8,298	8,305	2,646	9,470	4.42
124720	C E GHEENS	Dry/Plugged	8,098	8,102	2,646	9,470	4.43
72624	SUNSET REALTY & PLTG CO SWD	Dry/Plugged	3,460	3,656	3,264	9,191	4.44
143563	BDA G3 RE SU;GHEENS	Dry/Plugged	7,802	7,806	2,646	9,470	4.45
143563	BDA G3 RE SU;GHEENS	Dry/Plugged	7,940	7,960	2,646	9,470	4.45
143563	BDA G3 RE SU;GHEENS	Dry/Plugged	7,393	7,404	2,646	9,470	4.45
143563	BDA G3 RE SU;GHEENS	Dry/Plugged	7,350	7,360	2,646	9,470	4.45
142992	BDA 17 RB SU;GHEENS	Dry/Plugged	8,193	8,203	2,646	9,470	4.45
142992	BDA 17 RB SU;GHEENS	Dry/Plugged	8,224	8,234	2,646	9,470	4.45
143563	BDA G3 RE SU;GHEENS	Dry/Plugged	8,070	8,126	2,646	9,470	4.45
117650	GHEENS SWD	Dry/Plugged	8,068	8,071	2,646	9,470	4.49
116865	GHEENS SWD	Dry/Plugged	8,162	8,167	2,646	9,470	4.49
131744	C. E. GHEENS "A"	Dry/Plugged	8,237	8,254	2,646	9,470	4.57

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
145880	SR&P SWD	Dry/Plugged	8,310	8,313	3,277	9,243	4.68
145880	SR&P SWD	Dry/Plugged	8,924	8,933	3,277	9,243	4.68
145880	SR&P SWD	Dry/Plugged	3,600	3,710	3,277	9,243	4.68
146599	23 RA SUA;SR&P	Dry/Plugged	8,307	8,315	3,277	9,243	4.76
144761	30 RB SUA;SR&P	Dry/Plugged	8,460	8,466	3,398	9,369	4.84
144761	30 RB SUA;SR&P	Dry/Plugged	8,904	8,920	3,398	9,369	4.84
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	8,412	8,428	3,179	9,094	4.92
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	8,714	8,723	3,179	9,094	4.92
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	9,014	9,030	3,179	9,094	4.92
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	8,416	8,428	3,179	9,094	4.92
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	8,320	8,330	3,179	9,094	4.92
100133	PAR 10000 RV SU;SR&P	Dry/Plugged	8,310	8,316	3,277	9,243	4.95
140860	8 RV SUA;SR&P	Dry/Plugged	8,880	8,922	3,277	9,243	4.97
140860	8 RV SUA;SR&P	Dry/Plugged	8,880	8,898	3,277	9,243	4.97
146748	30 RB SUA;SR&P	Dry/Plugged	8,088	8,096	3,277	9,243	5.01
146748	30 RB SUA;SR&P	Dry/Plugged	8,479	8,496	3,277	9,243	5.01
229744	DELTA SEC CO INC	Shut-In/TA	6,988	6,994	3,312	9,867	5.02
229744	DELTA SEC CO INC	Shut-In/TA	8,376	8,430	3,312	9,867	5.02
229744	DELTA SEC CO INC	Shut-In/TA	8,516	8,608	3,312	9,867	5.02
70134	DELTA SEC CO INC A	Shut-In/TA	7,164	7,193	3,312	9,867	5.02
70134	DELTA SEC CO INC A	Shut-In/TA	7,433	7,441	3,312	9,867	5.02
81576	WATERFORD A	Dry/Plugged	8,999	9,040	3,183	9,699	5.02
146873	23 RB SUA;SR&P	Dry/Plugged	8,308	8,314	3,277	9,243	5.03
146873	23 RB SUA;SR&P	Dry/Plugged	8,454	8,464	3,277	9,243	5.03
46908	DELTA SEC CO INC	Dry/Plugged	6,773	6,788	3,225	9,679	5.03
120055	DELTA SEC CO INC A	Active Oil/Gas	7,420	7,443	3,312	9,867	5.04
120055	DELTA SEC CO INC A	Active Oil/Gas	7,083	7,100	3,312	9,867	5.04
69352	DELTA SEC CO INC A	Shut-In/TA	7,995	8,005	3,312	9,867	5.08
44121	DELTA SEC CO INC	Dry/Plugged	6,424	6,430	3,312	9,867	5.09
28313	9900 NAG RA SUL;SR&P	Dry/Plugged	9,050	9,058	3,197	9,137	5.12
158475	23 RB SUA;SR&P	Dry/Plugged	8,422	8,432	3,348	9,273	5.17
144596	SUNSET REALTY & PLANTING CO.	Dry/Plugged	8,651	8,666	3,348	9,273	5.17
28822	FANNIE S ABRAHAM	Dry/Plugged	9,079	9,110	3,277	9,243	5.19
228544	DELTA SEC CO INC	Shut-In/TA	8,230	8,569	3,160	9,527	5.19
228544	DELTA SEC CO INC	Shut-In/TA	7,970	8,012	3,160	9,527	5.19
228140	DELTA SEC CO INC	Shut-In/TA	7,076	7,112	3,225	9,679	5.20
228140	DELTA SEC CO INC	Shut-In/TA	7,132	7,236	3,225	9,679	5.20
228140	DELTA SEC CO INC	Shut-In/TA	7,282	7,355	3,225	9,679	5.20
48225	DELTA SEC CO INC	Shut-In/TA	5,339	5,362	3,160	9,527	5.21

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
48225	DELTA SEC CO INC	Shut-In/TA	7,923	7,344	3,160	9,527	5.21
43498	DELTA SEC CO INC	Dry/Plugged	6,370	6,380	3,225	9,679	5.22
65310	DELTA SEC CO INC A	Shut-In/TA	7,557	7,573	3,199	9,781	5.23
135648	DELTA SEC CO INC	Shut-In/TA	7,610	7,614	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,356	8,366	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,029	8,036	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,092	8,102	3,160	9,527	5.24
142607	DELTA SEC CO INC	Shut-In/TA	7,954	7,964	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	4,316	4,326	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	8,223	8,232	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	7,729	7,733	3,160	9,527	5.28
49127	DELTA SEC CO INC	Dry/Plugged	7,513	7,518	3,225	9,679	5.29
115147	DELTA SECURITIES COMPANY INC	Dry/Plugged	4,555	4,564	3,225	9,679	5.30
32073	DELTA SEC CO INC	Dry/Plugged	6,232	6,244	3,199	9,781	5.30
133621	DELTA SEC CO INC	Shut-In/TA	4,356	4,366	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,033	8,050	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,500	8,506	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	7,454	7,460	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,339	8,349	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,178	7,186	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,362	7,386	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,456	7,484	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	4,432	4,444	3,160	9,527	5.30
136793	DELTA SEC CO INC A	Shut-In/TA	6,888	6,936	3,199	9,781	5.31
136793	DELTA SEC CO INC A	Shut-In/TA	6,909	6,936	3,199	9,781	5.31
107815	DELTA SEC CO INC	Shut-In/TA	7,361	7,385	3,160	9,527	5.31
107815	DELTA SEC CO INC	Shut-In/TA	7,208	7,214	3,160	9,527	5.31
43987	DELTA SEC CO INC	Shut-In/TA	5,905	5,911	3,199	9,781	5.32
43987	DELTA SEC CO INC	Shut-In/TA	6,842	6,911	3,199	9,781	5.32
43987	DELTA SEC CO INC	Shut-In/TA	6,723	6,740	3,199	9,781	5.32
135895	DELTA SEC CO INC A	Shut-In/TA	7,420	7,465	3,199	9,781	5.32
135895	DELTA SEC CO INC A	Shut-In/TA	7,460	7,465	3,199	9,781	5.32
49301	DELTA SEC CO INC	Shut-In/TA	7,408	7,413	3,160	9,527	5.34
129754	DELTA SEC CO INC	Shut-In/TA	7,471	7,477	3,160	9,527	5.35
47614	DELTA SEC CO INC	Shut-In/TA	7,386	7,396	3,225	9,679	5.35
107323	DELTA SEC CO INC	Shut-In/TA	5,181	5,188	3,160	9,527	5.35
107323	DELTA SEC CO INC	Shut-In/TA	7,400	7,456	3,160	9,527	5.35
108647	DELTA SEC CO INC	Active Oil/Gas	4,070	4,076	3,160	9,527	5.36
63982	DELTA SEC CO INC A	Shut-In/TA	7,301	7,323	3,199	9,781	5.36
63982	DELTA SEC CO INC A	Shut-In/TA	7,301	7,337	3,199	9,781	5.36

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
124502	DELTA SEC CO INC	Shut-In/TA	6,662	6,668	3,199	9,781	5.38
228897	DELTA SEC CO INC	Shut-In/TA	7,678	7,967	3,199	9,781	5.39
49982	DELTA SEC CO INC	Shut-In/TA	3,819	3,826	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	5,814	5,850	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	4,869	4,876	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	4,044	4,051	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	7,190	7,209	3,160	9,527	5.39
53492	DELTA SEC CO INC	Dry/Plugged	6,303	6,339	3,199	9,781	5.39
54497	DELTA SEC CO INC	Dry/Plugged	6,864	6,873	3,225	9,679	5.41
64666	DELTA SEC CO INC A	Shut-In/TA	7,021	7,030	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	6,880	6,915	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	6,929	6,935	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	7,570	7,672	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	7,692	7,872	3,199	9,781	5.41
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	8,644	8,660	3,197	9,137	5.42
33003	SUNSET REALTY & PLANTING CO	Dry/Plugged	8,966	8,969	3,097	9,024	5.43
45887	DELTA SEC CO INC	Dry/Plugged	6,716	6,725	3,199	9,781	5.44
138411	DELTA SEC CO INC A	Shut-In/TA	6,963	6,979	3,199	9,781	5.45
53607	DELTA SEC CO INC	Unable to Locate	4,938	4,952	3,160	9,527	5.46
107282	DELTA SEC CO INC	Shut-In/TA	6,663	6,673	3,199	9,781	5.46
51264	DELTA SEC CO INC	Dry/Plugged	8,462	8,470	3,160	9,527	5.47
122403	DELTA SECURITIES	Dry/Plugged	7,476	7,484	3,160	9,527	5.47
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,250	8,258	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,610	8,630	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,862	8,885	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,877	8,885	3,097	9,024	5.51
41782	DELTA SEC CO INC	Dry/Plugged	4,712	4,733	3,160	9,527	5.52
45097	DELTA SEC CO INC	Dry/Plugged	6,718	6,732	3,199	9,781	5.52
252282	DELTA SEC CO INC	Shut-In/TA	6,834	6,838	3,132	9,506	5.54
252332	DELTA SEC CO INC	Active Oil/Gas	5,950	6,100	3,132	9,506	5.54
146062	SUNSET REALTY & PLANTING CO	Dry/Plugged	6,790	6,793	3,097	9,024	5.54
49500	DELTA SEC CO INC	Dry/Plugged	6,506	6,530	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	6,618	6,649	3,199	9,781	5.55

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
55112	DELTA SEC CO INC SWD	Active Injector	3,500	3,640	3,199	9,781	5.55
66725	DELTA SEC CO INC A	Shut-In/TA	6,977	6,995	3,199	9,781	5.58
252220	DELTA SEC CO INC	Shut-In/TA	5,490	5,495	3,132	9,506	5.58
252220	DELTA SEC CO INC	Shut-In/TA	5,990	6,160	3,132	9,506	5.58
252330	DELTA SEC CO INC	Active Oil/Gas	5,785	5,929	3,132	9,506	5.58
40228	BCBA A-1 VU;DELTA SEC CO INC	Dry/Plugged	5,756	5,796	3,160	9,527	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,015	9,020	3,218	9,156	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,015	9,023	3,218	9,156	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	8,720	8,740	3,218	9,156	5.59
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	8,374	8,378	3,097	9,024	5.60
129753	DELTA SEC CO INC	Active Oil/Gas	6,620	6,640	3,199	9,781	5.61
45492	DELTA SEC CO INC	Shut-In/TA	6,650	6,656	3,012	9,701	5.65
28136	U 9000 RE SUA;EDWARD DANNEL	Shut-In/TA	8,963	8,998	3,218	9,156	5.66
28136	U 9000 RE SUA;EDWARD DANNEL	Shut-In/TA	9,017	9,028	3,218	9,156	5.66
29704	DELTA SEC CO INC	Shut-In/TA	7,601	7,644	3,108	9,220	5.67
29704	DELTA SEC CO INC	Shut-In/TA	7,990	7,995	3,108	9,220	5.67
54150	BEBA B-1VU;DELTA SEC CO INC	Dry/Plugged	6,670	6,674	3,199	9,781	5.67
63196	DELTA SEC CO INC	Shut-In/TA	6,188	6,200	3,199	9,781	5.67
63196	DELTA SEC CO INC	Shut-In/TA	6,575	6,584	3,199	9,781	5.67
65309	DELTA SEC CO INC	Shut-In/TA	5,658	5,773	3,160	9,527	5.68
65309	DELTA SEC CO INC	Shut-In/TA	5,750	5,757	3,160	9,527	5.68
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	8,986	9,002	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	8,964	8,970	3,153	9,029	5.69
68506	DELTA SECURITIES CO INC A	Dry/Plugged	7,550	7,560	3,178	9,902	5.71
37405	DELTA SEC CO INC	Dry/Plugged	7,086	7,102	3,108	9,220	5.74
26195	SARAH SIMMS MALLORY	Shut-In/TA	8,794	8,830	3,218	9,156	5.75
116629	DELTA SEC CO INC	Active Oil/Gas	5,666	5,677	3,132	9,506	5.76
56431	DELTA SEC CO INC	Dry/Plugged	6,703	6,708	3,012	9,701	5.76
67681	DELTA SEC CO INC	Dry/Plugged	8,600	8,615	3,012	9,701	5.78
115146	DELTA SEC CO INC	Shut-In/TA	3,248	3,280	3,132	9,506	5.79
115146	DELTA SEC CO INC	Shut-In/TA	5,386	5,459	3,132	9,506	5.79
28307	DELTA SEC CO INC	Shut-In/TA	6,450	6,470	3,132	9,506	5.80
28307	DELTA SEC CO INC	Shut-In/TA	5,680	5,690	3,132	9,506	5.80
50502	DELTA SEC CO INC	Dry/Plugged	7,072	7,088	3,012	9,701	5.80

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
224366	49 R203 SUA;SR&P	Active Oil/Gas	7,134	7,136	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	8,162	8,172	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	7,732	7,736	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	8,352	8,356	3,017	8,910	5.82
153594	DELTA SEC CO INC	Shut-In/TA	5,638	5,703	3,132	9,506	5.82
153594	DELTA SEC CO INC	Shut-In/TA	5,559	5,568	3,132	9,506	5.82
153594	DELTA SEC CO INC	Shut-In/TA	5,436	5,478	3,132	9,506	5.82
41237	DELTA SEC CO INC	Dry/Plugged	5,704	5,714	3,108	9,220	5.83
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	8,950	8,960	3,153	9,029	5.84
42762	DELTA SEC CO INC	Dry/Plugged	3,225	3,230	3,108	9,220	5.86
59657	DELTA SECURITIES CO INC	Dry/Plugged	6,648	6,671	3,012	9,701	5.87
37799	DELTA SEC CO INC	Shut-In/TA	4,649	4,665	3,132	9,506	5.88
37799	DELTA SEC CO INC	Shut-In/TA	4,649	4,655	3,132	9,506	5.88
37799	DELTA SEC CO INC	Shut-In/TA	4,642	4,664	3,132	9,506	5.88
138891	DELTA SEC CO INC	Shut-In/TA	5,234	5,252	3,132	9,506	5.89
39296	DELTA SEC CO INC	Dry/Plugged	4,756	4,774	3,132	9,506	5.90
135871	DELTA SEC CO INC	Active Oil/Gas	6,544	6,557	3,012	9,701	5.92
135871	DELTA SEC CO INC	Active Oil/Gas	6,525	6,540	3,012	9,701	5.92
132509	SR&P SWD	Active Injector	6,010	6,030	3,017	8,910	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,462	3,562	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,370	3,566	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,150	3,282	3,097	8,938	5.92
40670	BCBA D3 RES SU;DSCI	Dry/Plugged	5,432	5,443	3,108	9,220	5.92
40670	BCBA D3 RES SU;DSCI	Dry/Plugged	5,432	5,388	3,108	9,220	5.92
40670	BCBA D3 RES SU;DSCI	Dry/Plugged	5,388	5,443	3,108	9,220	5.92
129752	DELTA SEC CO INC	Shut-In/TA	6,477	6,490	3,132	9,506	5.93
129752	DELTA SEC CO INC	Shut-In/TA	6,425	6,432	3,132	9,506	5.93
129752	DELTA SEC CO INC	Shut-In/TA	5,471	5,481	3,132	9,506	5.93
252351	DELTA SEC CO INC	Active Oil/Gas	4,790	4,942	3,108	9,220	5.93
252352	DELTA SEC CO INC	Active Oil/Gas	4,575	4,722	3,108	9,220	5.93

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
252351	DELTA SEC CO INC	Active Oil/Gas	4,356	4,364	3,108	9,220	5.93
27422	SR&P SWD	Active Injector	5,700	5,710	3,008	8,780	5.95
155929	DELTA SEC CO INC	Shut-In/TA	5,691	5,701	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	6,729	6,735	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,363	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,289	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,315	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	5,960	5,976	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	5,448	5,466	3,132	9,506	5.95
123691	LL&E PARADIS	Shut-In/TA	8,898	8,904	3,153	9,029	5.95
123691	LL&E PARADIS	Shut-In/TA	8,912	8,921	3,153	9,029	5.95
123691	LL&E PARADIS	Shut-In/TA	8,930	8,940	3,153	9,029	5.95
252333	DELTA SEC CO INC	Shut-In/TA	4,753	4,890	3,108	9,220	5.95
252300	DELTA SEC CO INC	Shut-In/TA	7,630	7,666	3,108	9,220	5.95
252300	DELTA SEC CO INC	Shut-In/TA	7,551	7,557	3,108	9,220	5.95
108222	DELTA SEC CO INC	Shut-In/TA	5,080	5,095	2,982	9,365	5.95
108222	DELTA SEC CO INC	Shut-In/TA	5,098	5,110	2,982	9,365	5.95
108222	DELTA SEC CO INC	Shut-In/TA	5,377	5,384	2,982	9,365	5.95
35974	DELTA SECURITIES CO INC	Dry/Plugged	7,600	7,610	3,108	9,220	5.95
155761	DELTA SEC CO INC	Shut-In/TA	6,872	6,868	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,945	6,955	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	5,412	5,424	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	7,466	7,533	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,250	6,265	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,230	6,250	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	5,894	5,900	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,185	6,189	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	5,433	5,436	3,108	9,220	5.97
252221	DELTA SEC CO INC	Active Oil/Gas	6,410	6,456	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	7,804	7,826	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	7,760	7,826	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	7,505	7,520	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	5,485	5,492	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	5,274	5,279	3,108	9,220	5.98

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
252331	DELTA SEC CO INC	Active Oil/Gas	5,614	5,730	3,108	9,220	5.98
62507	DELTA SEC CO INC	Dry/Plugged	6,669	6,674	3,012	9,701	5.98
109441	DELTA SEC CO INC	Active Oil/Gas	5,697	5,710	2,982	9,365	5.98
39763	DELTA SEC CO INC	Dry/Plugged	7,178	7,182	2,982	9,365	5.99
39763	DELTA SEC CO INC	Dry/Plugged	7,248	7,265	2,982	9,365	5.99
39763	DELTA SEC CO INC	Dry/Plugged	5,828	5,842	2,982	9,365	5.99
39763	DELTA SEC CO INC	Dry/Plugged	5,852	5,860	2,982	9,365	5.99
39763	DELTA SEC CO INC	Dry/Plugged	7,128	7,152	2,982	9,365	5.99
40051	DELTA SEC CO INC	Shut-In/TA	4,596	4,604	3,108	9,220	6.01
40051	DELTA SEC CO INC	Shut-In/TA	5,626	5,662	3,108	9,220	6.01
40051	DELTA SEC CO INC	Shut-In/TA	5,376	5,438	3,108	9,220	6.01
28576	DELTA SEC CO INC	Shut-In/TA	5,430	5,439	2,982	9,365	6.01
28576	DELTA SEC CO INC	Shut-In/TA	5,389	5,439	2,982	9,365	6.01
155930	DELTA SEC CO INC	Shut-In/TA	5,326	5,334	2,982	9,365	6.01
155930	DELTA SEC CO INC	Shut-In/TA	6,424	6,434	2,982	9,365	6.01
124223	DELTA SEC CO INC	Shut-In/TA	6,077	6,083	2,982	9,365	6.02
124223	DELTA SEC CO INC	Shut-In/TA	6,221	6,224	2,982	9,365	6.02
124223	DELTA SEC CO INC	Shut-In/TA	5,454	5,460	2,982	9,365	6.02
153593	DELTA SEC CO INC	Shut-In/TA	5,474	5,536	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	6,230	6,264	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,650	5,686	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	6,950	6,955	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,942	5,947	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,253	5,284	3,023	8,951	6.03
122066	DELTA SEC CO INC	Shut-In/TA	5,492	5,502	2,982	9,365	6.03
122066	DELTA SEC CO INC	Shut-In/TA	5,634	5,645	2,982	9,365	6.03
155760	DELTA SEC CO INC	Shut-In/TA	5,514	5,518	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,674	5,678	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,727	6,736	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,668	5,671	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,891	6,895	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,910	5,916	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,908	5,918	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,686	5,692	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,254	6,274	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	7,252	7,266	2,982	9,365	6.06
107279	DELTA SEC CO INC	Dry/Plugged	5,436	5,440	2,982	9,365	6.06
140064	DELTA SEC CO INC	Shut-In/TA	6,420	6,424	3,023	8,951	6.06
140064	DELTA SEC CO INC	Shut-In/TA	7,882	7,904	3,023	8,951	6.06

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
107281	DELTA SEC CO INC	Shut-In/TA	5,428	5,444	2,982	9,365	6.08
42351	DELTA SEC CO INC	Dry/Plugged	6,738	6,743	3,023	8,951	6.09
40996	DELTA SEC CO INC	Dry/Plugged	5,412	5,424	2,982	9,365	6.10
29668	LL&E PARADIS SWD	Dry/Plugged	4,505	4,690	3,013	8,710	6.10
29668	LL&E PARADIS SWD	Dry/Plugged	3,340	3,390	3,013	8,710	6.10
29668	LL&E PARADIS SWD	Dry/Plugged	3,250	3,390	3,013	8,710	6.10
38770	DELTA SEC CO INC	Shut-In/TA	5,392	5,437	2,982	9,365	6.12
162959	DELTA SEC CO INC	Shut-In/TA	6,117	6,123	2,982	9,365	6.12
162959	DELTA SEC CO INC	Shut-In/TA	5,300	6,305	2,982	9,365	6.12
35587	DELTA SEC CO INC	Dry/Plugged	3,799	3,803	3,023	8,951	6.13
28186	ARMSTRONG SWD	Active Injector	5,295	5,320	3,008	8,780	6.18
28186	ARMSTRONG SWD	Active Injector	5,090	5,110	3,008	8,780	6.18
28732	DELTA SEC CO INC	Dry/Plugged	6,479	6,494	2,982	9,365	6.23
970139	LL&E SWD	Dry/Plugged	3,221	3,500	3,008	8,780	6.25
970139	LL&E SWD	Dry/Plugged	3,329	3,379	3,008	8,780	6.25
118954	LL&E PARADIS	Shut-In/TA	8,470	8,490	3,145	8,940	6.34
29424	L L E PARADIS	Dry/Plugged	8,798	8,806	3,157	9,057	6.34
28970	DELTA SECURITIES CO INC	Dry/Plugged	8,020	8,025	3,023	8,951	6.35
27946	PARADIS SWD SYS #1	Active Injector	3,294	3,370	3,157	9,057	6.41
27946	PARADIS SWD SYS #1	Active Injector	3,320	3,370	3,157	9,057	6.41

1.11.7 Nearby Artificial Penetrations with Perforations Below the Injection Zone

The perforated intervals within 5 mi of the proposed area boundary and below the injection zone are listed in Table 1-22. The wells listed in the table include 8 active injectors, 40 active oil or gas wells, 229 dry holes or plugged and abandoned wells, 2 orphan wells, 49 shut-in or temporarily abandoned wells, and 1 well that was unable to be located for a total of 329 wells below the IZ.

Table 1-22 – Oil and gas wells within 5 mi of the area boundary with perforations below the injection zone.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
236901	VUB;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,102	11,112	3,460	9,818	0.63

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
236901	VUB;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,066	11,112	3,460	9,818	0.63
237172	VUC;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,902	11,910	3,460	9,818	0.64
237172	VUC;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,850	11,910	3,460	9,818	0.64
237039	VUA;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,404	11,414	3,460	9,818	0.64
237039	VUA;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,404	11,434	3,460	9,818	0.64
75831	LYDIA B SIMONEAUX ET AL	Dry/Plugged	10,945	10,954	3,460	9,818	0.65
166990	S J SIMONEAUX	Dry/Plugged	10,871	10,875	3,460	9,818	0.81
55235	LYDIA B SIMONEAUX ET AL	Dry/Plugged	11,012	11,032	3,391	9,556	1.47
238687	VUD;SIMONEAUX FAMILY LAND LLC	Dry/Plugged	11,832	11,840	3,576	10,106	1.70
250321	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,500	12,544	3,576	10,106	1.71
250321	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,554	12,600	3,576	10,106	1.71
250809	SIMONEAUX FAMILY LAND LLC A	Active Oil/Gas	13,774	13,940	3,576	10,106	1.71
250810	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,403	12,422	3,576	10,106	1.71
76172	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,881	10,902	3,356	9,418	1.71
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,911	10,924	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,000	11,020	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,002	11,016	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,881	10,896	3,356	9,418	1.72
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,270	10,274	3,356	9,418	1.90
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,265	10,267	3,356	9,418	1.90
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,277	10,287	3,356	9,418	1.90
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,296	10,316	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,261	10,271	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,185	11,200	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,882	10,900	3,372	9,417	1.92
85991	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,845	10,875	3,372	9,417	1.94

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	10,953	10,991	3,372	9,417	2.02
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	11,000	11,020	3,372	9,417	2.02
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	10,884	10,894	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,268	11,274	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,246	11,256	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,204	11,214	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,300	11,310	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,106	11,214	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,068	11,074	3,372	9,417	2.02
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,255	10,266	3,372	9,417	2.07
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,231	10,288	3,372	9,417	2.07
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,275	10,288	3,372	9,417	2.07
49904	LYDIA B SIMONEAUX ET AL	Dry/Plugged	10,318	10,322	3,372	9,417	2.08
49904	LYDIA B SIMONEAUX ET AL	Dry/Plugged	10,321	10,325	3,372	9,417	2.08
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	12,168	12,190	3,282	9,266	2.22
47529	L B SIMONEAUX SWD	Dry/Plugged	10,281	10,289	3,355	9,444	2.25
62581	LYDIA B SIMONEAUX ET AL	Dry/Plugged	12,142	12,156	3,296	9,302	2.30
141660	LYDIA B SIMONEAUX ET AL	Dry/Plugged	12,157	12,172	3,375	9,261	2.45
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	11,137	11,165	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	11,878	11,890	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	11,755	11,778	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	12,277	12,304	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	12,277	12,282	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	12,106	12,130	3,285	9,163	2.59
142882	SIM 10 RA SUA;SIMONEAUX	Shut-In/TA	11,104	11,120	3,285	9,163	2.59
100790	THERESA R.PLATT ET AL	Dry/Plugged	11,320	11,380	3,363	9,248	2.61
106633	SIM 10 SU C;T R PLATT	Dry/Plugged	12,214	12,235	3,363	9,248	2.61
49261	LYDIA B SIMONEAUX ET AL	Dry/Plugged	10,210	10,258	3,316	9,353	2.61

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
51300	CIB O CO RA SUA;SIMONEAUX	Dry/Plugged	11,228	11,248	3,479	9,968	2.63
46501	S J SIMONEAUX	Orphan Well	10,432	10,476	3,489	9,997	2.71
46501	S J SIMONEAUX	Orphan Well	10,604	10,623	3,489	9,997	2.71
34609	CIB O CO RA SUA;SIMONEAUX	Orphan Well	12,590	12,600	3,489	9,997	2.77
163509	SIM 10 RA SUC;SIMONEAUX	Dry/Plugged	12,118	12,130	3,314	9,143	2.78
163509	SIM 10 RA SUC;SIMONEAUX	Dry/Plugged	10,322	10,340	3,314	9,143	2.78
163509	SIM 10 RA SUC;SIMONEAUX	Dry/Plugged	11,360	11,366	3,314	9,143	2.78
163509	SIM 10 RA SUC;SIMONEAUX	Dry/Plugged	11,876	11,900	3,314	9,143	2.78
163509	SIM 10 RA SUC;SIMONEAUX	Dry/Plugged	12,121	12,148	3,314	9,143	2.78
28290	ST CHARLES LAND CO	Dry/Plugged	9,980	9,986	3,479	9,968	2.79
251069	SIMONEAUX	Shut-In/TA	11,440	11,464	3,489	9,997	2.80
251069	SIMONEAUX	Shut-In/TA	10,978	10,988	3,489	9,997	2.80
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,294	10,303	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,351	10,357	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,362	10,368	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,264	10,330	3,489	9,997	2.84
143484	9500 RF SUA; IRELAND	Dry/Plugged	11,148	11,155	3,310	9,254	2.89
143484	9500 RF SUA; IRELAND	Dry/Plugged	11,110	11,116	3,310	9,254	2.89
142608	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,138	11,150	3,310	9,254	2.91
142608	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,160	11,176	3,310	9,254	2.91
142608	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,120	11,150	3,310	9,254	2.91
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,364	11,378	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,746	11,765	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,293	11,304	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,829	11,838	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,874	11,886	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	12,150	12,175	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,344	11,358	3,314	9,143	2.97

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,274	11,288	3,314	9,143	2.97
54182	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	11,254	11,266	3,314	9,143	2.97
48662	ADAM DUFRENE UNIT	Dry/Plugged	11,354	11,364	3,547	10,057	2.97
144199	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,113	11,126	3,310	9,254	2.98
144199	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,135	11,149	3,310	9,254	2.98
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	12,420	12,431	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,765	11,778	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,744	11,756	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,083	11,092	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,367	11,378	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	12,342	12,351	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	12,377	12,396	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	12,150	12,169	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,914	11,930	3,314	9,143	2.99
50764	JOSEPH RATHBORNE LD & LBR	Dry/Plugged	11,121	11,144	3,314	9,143	2.99
144768	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,087	11,094	3,277	9,255	3.05
144768	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,107	11,115	3,277	9,255	3.05
144768	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,131	11,141	3,277	9,255	3.05
79342	RATHBORNE-SIMONEAUX ET AL UT 1	Dry/Plugged	10,282	10,286	3,285	9,163	3.07
140974	PAR 9500 RC SU;IRELAND	Dry/Plugged	11,041	11,062	3,217	9,091	3.12
60376	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	10,314	10,319	3,274	9,072	3.22
60376	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	10,252	10,260	3,274	9,072	3.22
60376	JOSEPH RATHBORNE LD & LBR CO	Dry/Plugged	10,290	10,300	3,274	9,072	3.22
173665	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,544	10,632	3,422	9,549	3.29
69737	JOSEPH RATHBORNE LD & LMBR CO	Dry/Plugged	10,303	10,314	3,251	9,093	3.31

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
139531	9900 RN SUA;IRELAND	Dry/Plugged	11,399	11,412	3,277	9,255	3.31
139531	9900 RN SUA;IRELAND	Dry/Plugged	11,508	11,520	3,277	9,255	3.31
141765	IRELAND FEE	Dry/Plugged	11,064	11,074	3,217	9,091	3.31
142176	PAR 8 RA SU;IRELAND	Dry/Plugged	9,570	9,630	3,422	9,549	3.32
142176	PAR 8 RA SU;IRELAND	Dry/Plugged	9,582	9,617	3,422	9,549	3.32
140912	W E LADY FEE	Dry/Plugged	11,036	11,046	3,217	9,091	3.33
140912	W E LADY FEE	Dry/Plugged	11,542	11,568	3,217	9,091	3.33
140912	W E LADY FEE	Dry/Plugged	10,984	11,010	3,217	9,091	3.33
141485	IRELAND FEE	Dry/Plugged	11,296	11,318	3,277	9,255	3.34
141485	IRELAND FEE	Dry/Plugged	11,395	11,419	3,277	9,255	3.34
65101	JOSEPH RATHBORNE LAND & LBR CO	Dry/Plugged	10,246	10,307	3,274	9,072	3.37
145982	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,264	11,272	3,277	9,255	3.37
139229	PAR 10000 RM SU;IRELAND	Dry/Plugged	11,376	11,404	3,277	9,255	3.37
142155	IRELAND FEE	Dry/Plugged	11,290	11,298	3,304	9,259	3.44
141993	PAR 8600 RB SU;IRELAND	Dry/Plugged	10,442	10,456	3,304	9,259	3.44
141993	PAR 8600 RB SU;IRELAND	Dry/Plugged	9,967	9,979	3,304	9,259	3.44
213183	PAR 9500 RD SU;LADY FEE	Dry/Plugged	11,490	11,502	3,217	9,091	3.47
213183	PAR 9500 RD SU;LADY FEE	Dry/Plugged	10,940	10,966	3,217	9,091	3.47
213183	PAR 9500 RD SU;LADY FEE	Dry/Plugged	11,474	11,536	3,217	9,091	3.47
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,316	11,326	3,277	9,255	3.48
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,168	11,180	3,277	9,255	3.48
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,326	11,330	3,277	9,255	3.48
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,275	11,282	3,277	9,255	3.48
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,210	11,236	3,277	9,255	3.48
151618	PAR 9900 RM SU;IRELAND	Dry/Plugged	11,300	11,317	3,277	9,255	3.48
173743	PAR 8 RA SU;IRELAND	Dry/Plugged	9,652	9,694	3,451	9,518	3.48
140934	W E LADY FEE	Dry/Plugged	11,508	11,524	3,217	9,091	3.48
140934	W E LADY FEE	Dry/Plugged	10,918	10,928	3,217	9,091	3.48
140934	W E LADY FEE	Dry/Plugged	11,406	11,434	3,217	9,091	3.48
140975	PAR L 9000 RM SU;IRELAND	Dry/Plugged	9,584	9,619	3,451	9,518	3.49
140975	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,536	10,636	3,451	9,518	3.49
193877	MITCHELL & NEELY INC	Dry/Plugged	10,292	10,298	3,276	9,048	3.50
193877	MITCHELL & NEELY INC	Dry/Plugged	10,245	10,280	3,276	9,048	3.50
198166	MITCHELL & NEELY INC	Dry/Plugged	10,407	10,415	3,276	9,048	3.50
205697	RATHBORNE LAND COMPANY INC	Dry/Plugged	11,282	11,293	3,274	9,072	3.50
205697	RATHBORNE LAND COMPANY INC	Dry/Plugged	10,258	10,270	3,274	9,072	3.50

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
205697	RATHBORNE LAND COMPANY INC	Dry/Plugged	10,308	10,324	3,274	9,072	3.50
140459	IRELAND FEE	Dry/Plugged	10,370	10,390	3,304	9,259	3.53
140459	IRELAND FEE	Dry/Plugged	10,334	10,348	3,304	9,259	3.53
140459	IRELAND FEE	Dry/Plugged	10,403	10,464	3,304	9,259	3.53
172019	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,545	10,658	3,451	9,518	3.54
172019	PAR L 9000 RM SU;IRELAND	Dry/Plugged	9,578	9,626	3,451	9,518	3.54
172019	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,544	10,674	3,451	9,518	3.54
142025	PAR 8 RA SU;IRELAND	Dry/Plugged	9,592	9,662	3,451	9,518	3.55
142025	PAR 8 RA SU;IRELAND	Dry/Plugged	9,610	9,626	3,451	9,518	3.55
82168	WATERFORD OIL CO	Dry/Plugged	11,203	11,216	3,476	10,075	3.56
138392	IRELAND FEE	Dry/Plugged	10,468	10,482	3,451	9,518	3.58
138392	IRELAND FEE	Dry/Plugged	10,424	10,438	3,451	9,518	3.58
137762	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,338	11,357	3,451	9,518	3.58
137762	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,337	11,352	3,451	9,518	3.58
137762	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,262	11,280	3,451	9,518	3.58
137762	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,355	10,370	3,451	9,518	3.58
137762	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,392	10,496	3,451	9,518	3.58
140873	IRELAND FEE	Dry/Plugged	10,430	10,452	3,451	9,518	3.69
140458	PAR 8 RA SU;IRELAND	Dry/Plugged	11,359	11,388	3,451	9,518	3.69
142436	PAR 10000 RO SU;IRELAND	Dry/Plugged	11,344	11,418	3,226	9,097	3.70
142703	IRELAND FEE	Dry/Plugged	10,796	10,818	3,226	9,097	3.70
142436	PAR 10000 RO SU;IRELAND	Dry/Plugged	11,362	11,404	3,226	9,097	3.70
142436	PAR 10000 RO SU;IRELAND	Dry/Plugged	11,344	11,404	3,226	9,097	3.70
93882	10250 SUA;J RATHBORNE JR 2	Dry/Plugged	10,251	10,259	3,214	9,040	3.70
140777	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,060	10,075	3,451	9,518	3.71
140777	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,500	11,530	3,451	9,518	3.71
140777	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,529	10,647	3,451	9,518	3.71
141189	IRELAND FEE	Dry/Plugged	9,583	9,600	3,451	9,518	3.71
151726	PAR 9900 RM SU;IRELAND FEE	Dry/Plugged	10,370	10,386	3,304	9,259	3.71
151726	PAR 9900 RM SU;IRELAND FEE	Dry/Plugged	11,166	11,190	3,304	9,259	3.71
151726	PAR 9900 RM SU;IRELAND FEE	Dry/Plugged	11,059	11,065	3,304	9,259	3.71
151726	PAR 9900 RM SU;IRELAND FEE	Dry/Plugged	11,165	11,190	3,304	9,259	3.71
74951	WATERFORD OIL CO	Dry/Plugged	10,200	10,207	2,812	9,617	3.73
137198	A N WIDENER FEE	Dry/Plugged	11,000	11,006	3,304	9,259	3.74
137198	A N WIDENER FEE	Dry/Plugged	10,725	10,750	3,304	9,259	3.74

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
137198	A N WIDENER FEE	Dry/Plugged	11,052	11,078	3,304	9,259	3.74
137198	A N WIDENER FEE	Dry/Plugged	10,726	10,750	3,304	9,259	3.74
137198	A N WIDENER FEE	Dry/Plugged	11,036	11,078	3,304	9,259	3.74
140217	PAR L 9000 RM SU;SR&P	Dry/Plugged	10,328	10,348	3,304	9,259	3.77
140217	PAR L 9000 RM SU;SR&P	Dry/Plugged	10,299	10,318	3,304	9,259	3.77
140217	PAR L 9000 RM SU;SR&P	Dry/Plugged	10,258	10,357	3,304	9,259	3.77
138205	PAR 9500 RD SU;IRELAND	Dry/Plugged	10,798	10,809	3,226	9,097	3.77
138205	PAR 9500 RD SU;IRELAND	Dry/Plugged	10,750	10,809	3,226	9,097	3.77
140803	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,277	10,290	3,451	9,518	3.81
140803	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,310	10,330	3,451	9,518	3.81
140803	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,363	10,399	3,451	9,518	3.81
138869	PAR 8 RA SU;IRELAND	Dry/Plugged	11,238	11,254	3,451	9,518	3.86
139318	IRELAND FEE	Dry/Plugged	10,496	10,515	3,451	9,518	3.86
138869	PAR 8 RA SU;IRELAND	Dry/Plugged	11,282	11,306	3,451	9,518	3.86
142089	PAR L 9000 RM SU;IRELAND	Dry/Plugged	9,564	9,590	3,462	9,519	3.88
151727	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,274	10,284	3,451	9,518	3.89
151727	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,274	10,382	3,451	9,518	3.89
151727	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,320	10,343	3,451	9,518	3.89
151727	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,182	11,206	3,451	9,518	3.89
143107	SUNSET REALTY & PLANTING CO	Dry/Plugged	11,014	11,023	3,226	9,097	3.94
143107	SUNSET REALTY & PLANTING CO	Dry/Plugged	11,078	11,110	3,226	9,097	3.94
131987	SUNSET REALTY & PLANTING CO.	Dry/Plugged	11,008	11,018	3,304	9,259	3.96
139475	IRELAND FEE	Dry/Plugged	10,156	10,168	3,226	9,097	3.98
141942	PAR 8600 RB SU	Dry/Plugged	10,090	10,096	3,511	9,686	4.04
140296	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,324	10,350	3,462	9,519	4.05
140296	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,290	10,420	3,462	9,519	4.05
43820	PAR 10000 RM SU;SR&P	Dry/Plugged	10,957	10,970	3,361	9,329	4.06
43820	PAR 10000 RM SU;SR&P	Dry/Plugged	10,958	10,970	3,361	9,329	4.06
173659	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,547	10,648	3,462	9,519	4.06
146561	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,903	9,912	3,185	9,071	4.06
146561	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,902	9,924	3,185	9,071	4.06
146561	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,984	10,012	3,185	9,071	4.06
146561	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,903	9,924	3,185	9,071	4.06
154587	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,844	9,854	3,226	9,097	4.07
154587	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,810	9,864	3,226	9,097	4.07
154587	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	10,278	10,366	3,226	9,097	4.07
154587	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,814	9,864	3,226	9,097	4.07
154587	PAR 9500 RC7 SU;IRELAND	Dry/Plugged	9,816	9,836	3,226	9,097	4.07

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
95241	9700' SUA; J. RATHBORNE TR3	Dry/Plugged	9,690	9,695	3,214	9,040	4.07
153596	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,286	10,382	3,462	9,519	4.08
153596	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,346	10,370	3,462	9,519	4.08
153596	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,357	10,362	3,462	9,519	4.08
153596	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,321	10,348	3,462	9,519	4.08
140523	IRELAND FEE	Dry/Plugged	11,327	11,353	3,462	9,519	4.10
140859	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,396	10,503	3,462	9,519	4.10
140859	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,396	10,410	3,462	9,519	4.10
140859	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,396	10,408	3,462	9,519	4.10
140859	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,438	10,494	3,462	9,519	4.10
140523	IRELAND FEE	Dry/Plugged	11,111	11,122	3,462	9,519	4.10
140859	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,430	10,503	3,462	9,519	4.10
146327	PAR PZ RU SU;IRELAND	Dry/Plugged	10,611	10,660	3,185	9,071	4.14
146327	PAR PZ RU SU;IRELAND	Dry/Plugged	10,611	10,640	3,185	9,071	4.14
250965	EMC FEE	Active Oil/Gas	13,428	13,530	3,642	10,135	4.15
250965	EMC FEE	Active Oil/Gas	13,578	13,619	3,642	10,135	4.15
250903	EMC FEE	Active Oil/Gas	12,236	12,266	3,642	10,135	4.15
143108	SUNSET REALTY & PLANT. CO.	Dry/Plugged	10,832	10,841	3,361	9,329	4.15
143108	SUNSET REALTY & PLANT. CO.	Dry/Plugged	10,106	10,118	3,361	9,329	4.15
143108	SUNSET REALTY & PLANT. CO.	Dry/Plugged	10,167	10,185	3,361	9,329	4.15
143108	SUNSET REALTY & PLANT. CO.	Dry/Plugged	10,832	10,840	3,361	9,329	4.15
251823	EMC FEE	Active Oil/Gas	11,410	11,462	3,642	10,135	4.15
251823	EMC FEE	Active Oil/Gas	11,364	11,462	3,642	10,135	4.15
251823	EMC FEE	Active Oil/Gas	11,260	11,300	3,642	10,135	4.15
140271	U 9000 RM VUA;IRELAND	Dry/Plugged	10,386	10,394	3,462	9,519	4.15
140271	U 9000 RM VUA;IRELAND	Dry/Plugged	10,428	10,445	3,462	9,519	4.15
140271	U 9000 RM VUA;IRELAND	Dry/Plugged	11,277	11,290	3,462	9,519	4.15
140271	U 9000 RM VUA;IRELAND	Dry/Plugged	10,384	10,394	3,462	9,519	4.15
139732	IRELAND FEE	Dry/Plugged	11,379	11,408	3,462	9,519	4.15
146353	PAR PZ RU SU;IRELAND	Dry/Plugged	10,012	10,035	3,226	9,097	4.16
146353	PAR PZ RU SU;IRELAND	Dry/Plugged	10,092	10,123	3,226	9,097	4.16
146353	PAR PZ RU SU;IRELAND	Dry/Plugged	10,642	10,684	3,226	9,097	4.16
56712	WATERFORD OIL CO	Shut-In/TA	11,449	11,534	3,642	10,135	4.17
114452	WATERFORD OIL CO	Active Oil/Gas	11,160	11,180	3,642	10,135	4.17
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,558	10,600	3,226	9,097	4.18
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,558	10,572	3,226	9,097	4.18

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,558	10,570	3,226	9,097	4.18
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,157	10,186	3,226	9,097	4.18
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,626	10,640	3,226	9,097	4.18
145899	PAR PZ RU SU;SR&P	Dry/Plugged	10,157	10,166	3,226	9,097	4.18
147720	PAR PZ RU SU;IRELAND	Dry/Plugged	10,618	10,635	3,185	9,071	4.20
147720	PAR PZ RU SU;IRELAND	Dry/Plugged	10,654	10,664	3,185	9,071	4.20
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,484	10,550	3,185	9,071	4.23
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,484	10,506	3,185	9,071	4.23
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,570	10,586	3,185	9,071	4.23
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,484	10,586	3,185	9,071	4.23
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,484	10,494	3,185	9,071	4.23
145287	PAR PZ RU SU;SR&P	Dry/Plugged	10,562	10,582	3,185	9,071	4.23
139388	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,099	10,134	3,264	9,191	4.24
139388	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,126	10,134	3,264	9,191	4.24
139738	9 RC SU A; SR&P	Dry/Plugged	9,575	9,583	3,264	9,191	4.24
140724	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,524	10,542	3,511	9,686	4.25
140724	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,520	10,612	3,511	9,686	4.25
140724	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,015	10,034	3,511	9,686	4.25
141694	IRELAND FEE	Dry/Plugged	11,389	11,416	3,511	9,686	4.25
136377	IRELAND FEE	Dry/Plugged	11,014	11,046	3,462	9,519	4.28
136377	IRELAND FEE	Dry/Plugged	10,698	10,709	3,462	9,519	4.28
148521	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,422	10,437	3,462	9,519	4.28
148521	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,400	10,410	3,462	9,519	4.28
148521	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,395	10,410	3,462	9,519	4.28
148521	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,140	11,150	3,462	9,519	4.28
148521	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,390	10,460	3,462	9,519	4.28
134377	PAR 10000 R 10 SU;SR&P	Dry/Plugged	11,212	11,224	3,361	9,329	4.28
133937	PAR 9900 R 10 SU;SR&P	Dry/Plugged	10,870	10,880	3,361	9,329	4.28
133937	PAR 9900 R 10 SU;SR&P	Dry/Plugged	10,846	10,860	3,361	9,329	4.28
133937	PAR 9900 R 10 SU;SR&P	Dry/Plugged	10,996	11,005	3,361	9,329	4.28
165206	WATERFORD OIL CO	Shut-In/TA	10,766	10,776	3,605	10,093	4.31
165206	WATERFORD OIL CO	Shut-In/TA	10,986	10,990	3,605	10,093	4.31
85846	WATERFORD OIL CO B	Dry/Plugged	11,044	11,075	3,541	10,087	4.33
88151	WATERFORD OIL CO B	Dry/Plugged	10,670	10,688	3,541	10,087	4.33
42979	VUB;SR&P	Dry/Plugged	10,850	10,870	3,361	9,329	4.36
42979	VUB;SR&P	Dry/Plugged	10,054	10,064	3,361	9,329	4.36
28980	C E GHEENS	Dry/Plugged	10,400	10,410	2,707	9,217	4.36
142339	SUNSET REALTY & PLANTING CO.	Dry/Plugged	9,502	9,531	3,361	9,329	4.37

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
140725	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,434	11,461	3,520	9,683	4.39
140725	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,556	10,660	3,520	9,683	4.39
141051	IRELAND FEE	Dry/Plugged	10,056	10,068	3,520	9,683	4.39
141530	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,284	11,296	3,458	9,526	4.39
141908	IRELAND FEE	Dry/Plugged	10,496	10,507	3,458	9,526	4.39
141530	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,411	11,430	3,458	9,526	4.39
141530	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,438	10,564	3,458	9,526	4.39
216996	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,493	10,563	3,179	9,094	4.46
216996	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,435	10,600	3,179	9,094	4.46
38004	PAR PARADIS RT SU	Dry/Plugged	10,535	10,584	3,179	9,094	4.48
38004	PAR PARADIS RT SU	Dry/Plugged	10,532	10,584	3,179	9,094	4.48
131147	PAR 9900 R 10 SU;SR&P	Dry/Plugged	11,120	11,128	3,398	9,369	4.49
131147	PAR 9900 R 10 SU;SR&P	Dry/Plugged	10,994	11,012	3,398	9,369	4.49
141584	9900 RB SUA;IRELAND	Dry/Plugged	11,353	11,369	3,458	9,526	4.55
39598	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,504	10,604	3,264	9,191	4.56
39598	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,504	10,540	3,264	9,191	4.56
39598	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,400	10,573	3,264	9,191	4.56
79447	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,894	9,956	3,264	9,191	4.56
39598	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,560	10,604	3,264	9,191	4.56
138978	10000 R015 SUA;SR&P	Dry/Plugged	10,924	10,946	3,398	9,369	4.58
138978	10000 R015 SUA;SR&P	Dry/Plugged	11,010	11,024	3,398	9,369	4.58
139282	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,995	10,010	3,398	9,369	4.58
126297	PAR L 9000 RA SU;SR&P	Dry/Plugged	9,928	9,941	3,398	9,369	4.59
126297	PAR L 9000 RA SU;SR&P	Dry/Plugged	9,992	10,016	3,398	9,369	4.59
71015	NETHERLANDS CORP	Shut-In/TA	11,522	11,534	3,388	10,108	4.61
135705	PAR 9900 R 10 SU;SR&P	Dry/Plugged	11,080	11,104	3,398	9,369	4.64
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,206	10,216	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,206	10,430	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,340	10,350	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,310	10,318	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,284	10,296	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,936	9,944	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,206	10,221	3,179	9,094	4.67

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,356	10,414	3,179	9,094	4.67
37687	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,494	9,504	3,179	9,094	4.67
137504	8550 STRAY RA SUA;SR&P	Dry/Plugged	9,517	9,535	3,398	9,369	4.72
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,278	10,284	3,277	9,243	4.74
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,246	10,284	3,277	9,243	4.74
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,769	9,826	3,277	9,243	4.74
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,254	10,448	3,277	9,243	4.74
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,874	9,881	3,277	9,243	4.74
144625	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,770	9,826	3,277	9,243	4.74
141764	SUNSET REALTY & PLANTING CO.	Dry/Plugged	10,026	10,036	3,398	9,369	4.75
142704	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,536	10,640	3,458	9,526	4.76
142704	PAR L 9000 RM SU;IRELAND	Dry/Plugged	11,450	11,472	3,458	9,526	4.76
142899	IRELAND FEE	Dry/Plugged	10,536	10,549	3,458	9,526	4.76
142899	IRELAND FEE	Dry/Plugged	10,536	10,542	3,458	9,526	4.76
142704	PAR L 9000 RM SU;IRELAND	Dry/Plugged	10,558	10,640	3,458	9,526	4.76
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,348	10,358	3,179	9,094	4.80
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,304	10,358	3,179	9,094	4.80
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,136	10,368	3,179	9,094	4.80
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,199	10,211	3,179	9,094	4.80
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,146	10,170	3,179	9,094	4.80
37290	PAR PARADIS RT SU;SR&P	Dry/Plugged	10,326	10,336	3,179	9,094	4.80
144761	30 RB SUA;SR&P	Dry/Plugged	9,697	9,714	3,398	9,369	4.84
132708	SUNSET REALTY & PLANTING CO.	Dry/Plugged	9,846	9,862	3,398	9,369	4.84
121155	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,980	10,000	3,398	9,369	4.86
121959	SUNSET REALTY &PLANTING CO.	Dry/Plugged	10,050	10,060	3,398	9,369	4.86
128017	LOUIS J ROUSSEL ET AL	Dry/Plugged	10,012	10,044	2,926	8,916	4.88
128017	LOUIS J ROUSSEL ET AL	Dry/Plugged	10,036	10,044	2,926	8,916	4.88
142026	IRELAND FEE	Dry/Plugged	11,433	11,441	3,458	9,526	4.92
151797	U 9000 RC4 SUA;SR&P	Dry/Plugged	9,958	9,994	3,179	9,094	4.92

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
38337	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,260	10,272	3,277	9,243	4.93
100133	PAR 10000 RV SU;SR&P	Dry/Plugged	9,926	9,951	3,277	9,243	4.95
100133	PAR 10000 RV SU;SR&P	Dry/Plugged	9,306	9,315	3,277	9,243	4.95
140860	8 RV SUA;SR&P	Dry/Plugged	9,704	9,741	3,277	9,243	4.97
124127	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,838	9,900	3,197	9,137	5.07
33985	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,338	9,360	3,197	9,137	5.07
34801	SUNSET REALTY & PLANTING CO	Dry/Plugged	11,042	11,102	3,277	9,243	5.09
165911	18 RA SUA;C E GHEENS	Dry/Plugged	10,296	10,302	2,608	9,454	5.10
165911	18 RA SUA;C E GHEENS	Dry/Plugged	11,510	11,548	2,608	9,454	5.10
165911	18 RA SUA;C E GHEENS	Dry/Plugged	11,154	11,202	2,608	9,454	5.10
165911	18 RA SUA;C E GHEENS	Dry/Plugged	11,202	11,222	2,608	9,454	5.10
28313	9900 NAG RA SUL;SR&P	Dry/Plugged	10,093	10,101	3,197	9,137	5.12
28313	9900 NAG RA SUL;SR&P	Dry/Plugged	9,590	9,607	3,197	9,137	5.12
158475	23 RB SUA;SR&P	Dry/Plugged	10,224	10,238	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,136	10,152	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,218	10,244	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,275	10,287	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,765	10,782	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,334	10,343	3,348	9,273	5.17
158475	23 RB SUA;SR&P	Dry/Plugged	10,218	10,238	3,348	9,273	5.17
28219	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,390	10,405	2,989	8,824	5.18
28822	FANNIE S ABRAHAM	Dry/Plugged	10,196	10,284	3,277	9,243	5.19
28822	FANNIE S ABRAHAM	Dry/Plugged	9,960	9,968	3,277	9,243	5.19
28822	FANNIE S ABRAHAM	Dry/Plugged	9,912	9,946	3,277	9,243	5.19
157511	U 9000 RD SUA;A DUFRENE	Dry/Plugged	10,042	10,072	3,348	9,273	5.21
157511	U 9000 RD SUA;A DUFRENE	Dry/Plugged	10,125	10,138	3,348	9,273	5.21
157511	U 9000 RD SUA;A DUFRENE	Dry/Plugged	10,545	10,562	3,348	9,273	5.21
123484	LWR 9000 RB SUA; D P CANDIES	Dry/Plugged	10,034	10,046	3,400	9,393	5.21
123484	LWR 9000 RB SUA; D P CANDIES	Dry/Plugged	10,023	10,046	3,400	9,393	5.21
72071	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,970	9,994	2,924	8,893	5.24
32657	9900 NAG RA SUK;SR&P	Shut-In/TA	9,628	9,646	3,097	9,024	5.28
129307	PAR 9500 NAG RA SU;SR&P	Shut-In/TA	9,294	9,308	3,097	9,024	5.28
29123	BUSH	Dry/Plugged	9,752	9,794	3,197	9,137	5.28

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
29123	BUSH	Dry/Plugged	9,782	9,794	3,197	9,137	5.28
29123	BUSH	Dry/Plugged	9,853	9,859	3,197	9,137	5.28
28080	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,278	10,293	2,959	8,800	5.30
112353	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,944	9,978	2,959	8,800	5.30
26577	KATE PARETI	Dry/Plugged	10,078	10,088	2,924	8,893	5.33
33253	10000 RC SUF;SR&P	Shut-In/TA	9,660	9,670	3,197	9,137	5.34
33253	10000 RC SUF;SR&P	Shut-In/TA	10,043	10,047	3,197	9,137	5.34
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	10,014	10,044	3,197	9,137	5.42
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	10,378	10,384	3,197	9,137	5.42
33003	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,069	10,076	3,097	9,024	5.43
25716	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,825	9,836	2,924	8,893	5.44
23895	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,032	9,060	3,017	8,910	5.48
23895	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,425	9,442	3,017	8,910	5.48
23895	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,047	9,060	3,017	8,910	5.48
26675	9900 NAG RA SUJ;SR&P	Dry/Plugged	9,776	9,792	3,017	8,910	5.49
26675	9900 NAG RA SUJ;SR&P	Dry/Plugged	10,054	10,082	3,017	8,910	5.49
85094	SUNSET REALTY & PLANTING CO	Active Oil/Gas	10,004	10,012	3,097	9,024	5.51
85094	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,970	9,978	3,097	9,024	5.51
27929	PAR PZ RAB SU;SR&P	Dry/Plugged	10,275	10,289	2,959	8,800	5.52
78943	9900 NAG RA SUH; SR&P	Dry/Plugged	9,858	9,910	2,959	8,800	5.52
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,748	9,784	3,097	9,024	5.54
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,822	9,828	3,097	9,024	5.54
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	10,080	10,090	3,097	9,024	5.54
135741	PAR PZ RAB SU;SR&P	Dry/Plugged	10,000	10,010	3,017	8,910	5.55
135741	PAR PZ RAB SU;SR&P	Dry/Plugged	10,974	10,994	3,017	8,910	5.55
28185	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,102	10,124	2,959	8,800	5.57
28185	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,101	10,112	2,959	8,800	5.57

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
161448	THE LEON GODCHAUX CO LTD	Dry/Plugged	10,056	10,062	3,400	9,393	5.57
72110	10000 RC SUB;J DAMICO	Shut-In/TA	10,010	10,022	3,348	9,273	5.57
73600	JOSEPH DAMICO	Shut-In/TA	9,864	9,893	3,348	9,273	5.57
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,355	9,366	3,218	9,156	5.59
133406	THE LEON GODCHAUX CO LTD	Dry/Plugged	9,970	10,044	3,348	9,273	5.59
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,582	9,626	3,097	9,024	5.60
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	10,010	10,028	3,097	9,024	5.60
29260	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,704	9,712	3,017	8,910	5.62
29260	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,476	9,482	3,017	8,910	5.62
101757	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,339	9,362	3,017	8,910	5.62
29260	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,046	10,058	3,017	8,910	5.62
29260	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,070	9,074	3,017	8,910	5.62
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,842	10,900	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,194	10,222	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,314	10,340	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	9,990	10,002	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	9,972	10,002	3,153	9,029	5.66
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,051	10,104	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	11,166	11,170	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,603	10,614	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,078	10,104	3,153	9,029	5.69
28883	MRS J GROS ET AL	Dry/Plugged	10,371	10,390	3,013	8,710	5.70
110977	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,004	10,016	3,017	8,910	5.71
27537	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,075	10,100	3,017	8,910	5.71
110977	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,844	9,858	3,017	8,910	5.71
110977	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,009	10,022	3,017	8,910	5.71

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
28659	PAR PZ RAB SU;SR&P	Dry/Plugged	10,236	10,266	2,959	8,800	5.71
110976	CLARK V SINGLETON	Active Oil/Gas	9,856	9,900	2,959	8,800	5.72
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	10,201	10,210	2,959	8,800	5.72
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	9,665	9,673	2,959	8,800	5.72
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	9,666	9,673	2,959	8,800	5.72
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,600	9,612	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,580	9,593	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	10,010	10,028	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,600	9,608	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,993	10,019	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	10,081	10,127	3,218	9,156	5.75
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	10,820	10,840	3,017	8,910	5.81
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,864	9,876	3,017	8,910	5.81
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,464	9,478	3,017	8,910	5.81
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,460	9,462	3,017	8,910	5.81
111012	SUNSET REALTY & PLANTING CO	Active Oil/Gas	10,236	10,258	3,017	8,910	5.81
73411	10000 RC SUC;PROVIDENCE LTD CO	Dry/Plugged	9,947	9,953	3,265	9,168	5.81
73411	10000 RC SUC;PROVIDENCE LTD CO	Dry/Plugged	9,944	9,953	3,265	9,168	5.81
118588	THE LEON GODCHAUX CO LTD	Dry/Plugged	10,101	10,114	3,410	9,403	5.81
118588	THE LEON GODCHAUX CO LTD	Dry/Plugged	10,100	10,114	3,410	9,403	5.81
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,958	9,964	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,155	10,191	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,984	9,992	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,972	9,980	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,155	10,175	3,153	9,029	5.83

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,184	10,200	3,153	9,029	5.83
217287	MFG REC PUB CO	Active Oil/Gas	10,294	10,297	3,153	9,029	5.83
217287	MFG REC PUB CO	Active Oil/Gas	13,309	13,316	3,153	9,029	5.83
217287	MFG REC PUB CO	Active Oil/Gas	10,302	10,305	3,153	9,029	5.83
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,982	9,998	3,153	9,029	5.84
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,656	9,666	3,153	9,029	5.84
116228	PAR PZ RAB SU;SR&P	Shut-In/TA	9,926	9,936	3,017	8,910	5.86
116228	PAR PZ RAB SU;SR&P	Shut-In/TA	10,128	10,146	3,017	8,910	5.86
28323	10000 NAG RA SUD; W J LAUGHLIN	Dry/Plugged	10,072	10,084	3,013	8,710	5.86
116419	SUNSET REALTY & PLANTING CO.	Dry/Plugged	10,194	10,208	3,097	8,938	5.89
114881	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,860	9,874	3,097	8,938	5.89
74292	PROVIDENCE LAND CORP	Dry/Plugged	10,228	10,236	3,265	9,168	5.90
27544	PAR 10000 NAG RA SU;LAWLER	Dry/Plugged	10,142	10,150	3,008	8,780	5.92
27544	PAR 10000 NAG RA SU;LAWLER	Dry/Plugged	9,920	9,932	3,008	8,780	5.92
133566	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,951	9,964	3,017	8,910	5.92
132509	SR&P SWD	Active Injector	10,828	10,912	3,017	8,910	5.92
132509	SR&P SWD	Active Injector	10,986	10,998	3,017	8,910	5.92
69821	SUNSET REALTY & PLANTING CO	Dry/Plugged	10,843	10,933	3,017	8,910	5.92
111542	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,590	9,634	3,017	8,910	5.92
69821	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,898	9,908	3,017	8,910	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	9,888	9,908	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	9,442	9,451	3,097	8,938	5.92
116118	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,687	9,710	3,008	8,780	5.94
27686	PAR PZ RAB SU;SR&P	Shut-In/TA	9,959	9,970	3,008	8,780	5.95
110978	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,671	9,702	3,008	8,780	5.95
27686	PAR PZ RAB SU;SR&P	Shut-In/TA	9,671	9,702	3,008	8,780	5.95

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
27422	SR&P SWD	Active Injector	10,100	10,104	3,008	8,780	5.95
27422	SR&P SWD	Active Injector	9,826	9,856	3,008	8,780	5.95
27422	SR&P SWD	Active Injector	9,902	9,910	3,008	8,780	5.95
124470	LL&E PARADIS	Active Oil/Gas	10,758	10,788	3,153	9,029	5.95
123653	PAR PZ RAB SU;LL&E	Dry/Plugged	9,866	9,890	3,153	9,029	5.96
209806	LL&E PARADIS	Shut-In/TA	10,218	10,228	3,153	9,029	5.96
140861	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,975	9,990	3,017	8,910	5.97
140861	SUNSET REALTY & PLANTING CO	Dry/Plugged	9,790	9,803	3,017	8,910	5.97
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,872	9,884	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,874	9,876	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,288	10,330	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,248	10,330	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,116	10,145	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,916	9,934	3,153	9,029	5.98
28297	PROVIDENCE LAND CORP	Dry/Plugged	10,059	10,065	3,265	9,168	6.02
78123	PROVIDENCE LAND CORP.	Dry/Plugged	11,064	11,074	3,265	9,168	6.03
78942	PROVIDENCE LAND CORP	Dry/Plugged	9,421	9,450	3,265	9,168	6.03
79558	10000 RC SUD; MRP	Dry/Plugged	10,019	10,044	3,265	9,168	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,064	10,074	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,858	9,874	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,850	9,874	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,211	10,232	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,708	10,770	3,097	8,938	6.07
21906	PAR 9500 NAG RA SU;LL&E	Dry/Plugged	9,158	9,186	3,097	8,938	6.10
118424	PAR PZ RA-B SU	Dry/Plugged	9,875	9,895	3,097	8,938	6.11
157766	LL&E PARADIS	Dry/Plugged	10,346	10,394	3,097	8,938	6.13
157766	LL&E PARADIS	Dry/Plugged	10,192	10,242	3,097	8,938	6.13
157766	LL&E PARADIS	Dry/Plugged	9,850	9,862	3,097	8,938	6.13
157766	LL&E PARADIS	Dry/Plugged	11,280	11,314	3,097	8,938	6.13
157766	LL&E PARADIS	Dry/Plugged	10,859	10,938	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,839	9,853	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,058	10,070	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,328	10,364	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,205	10,226	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,830	9,851	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,830	9,898	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,158	10,163	3,097	8,938	6.13
115178	LL&E PARADIS	Active Oil/Gas	10,171	10,190	3,097	8,938	6.13
114074	LL&E PARADIS	Shut-In/TA	9,570	9,592	3,097	8,938	6.13

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
72019	PROVIDENCE LAND CORP.	Dry/Plugged	10,010	10,018	3,157	9,057	6.13
72019	PROVIDENCE LAND CORP.	Dry/Plugged	10,941	10,945	3,157	9,057	6.13
72019	PROVIDENCE LAND CORP.	Dry/Plugged	10,666	10,670	3,157	9,057	6.13
73821	PAR RA SUE;PROVIDENCE LD CORP	Dry/Plugged	10,051	10,057	3,157	9,057	6.13
73821	PAR RA SUE;PROVIDENCE LD CORP	Dry/Plugged	10,042	10,046	3,157	9,057	6.13
123251	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,438	9,443	3,097	8,938	6.18
123251	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,224	9,248	3,097	8,938	6.18
28186	ARMSTRONG SWD	Active Injector	9,927	10,002	3,008	8,780	6.18
75857	MFG REC PUB CO	Dry/Plugged	11,213	11,217	3,265	9,168	6.20
77007	10,000 RC SUE; MRP	Dry/Plugged	9,970	9,990	3,265	9,168	6.20
101758	LL&E PARADIS	Active Oil/Gas	9,332	9,356	3,008	8,780	6.23
110792	PAR PZ RAB SU;LL&E	Dry/Plugged	11,316	11,440	3,097	8,938	6.23
110792	PAR PZ RAB SU;LL&E	Dry/Plugged	11,574	11,595	3,097	8,938	6.23
110792	PAR PZ RAB SU;LL&E	Dry/Plugged	11,430	11,440	3,097	8,938	6.23
110792	PAR PZ RAB SU;LL&E	Dry/Plugged	9,902	9,912	3,097	8,938	6.23
36302	LL&E PARADIS	Active Oil/Gas	9,986	9,998	3,008	8,780	6.23
36302	LL&E PARADIS	Active Oil/Gas	9,793	9,798	3,008	8,780	6.23
36302	LL&E PARADIS	Active Oil/Gas	9,542	9,552	3,008	8,780	6.23
113257	LL&E PARADIS	Active Oil/Gas	9,980	10,004	3,157	9,057	6.24
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,946	9,954	3,157	9,057	6.24
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,979	9,984	3,157	9,057	6.24
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,980	10,000	3,157	9,057	6.24
115207	PAR 10000 NAG RA SU;LL&E	Shut-In/TA	9,962	9,966	3,097	8,938	6.24
115207	PAR 10000 NAG RA SU;LL&E	Shut-In/TA	9,627	9,660	3,097	8,938	6.24
249458	GHEENS RA SUA;RATHBORNE LD CO	Dry/Plugged	12,595	12,675		8,730	6.25
27543	LL&E SWD	Active Injector	10,036	10,045	3,008	8,780	6.27
71569	MFG REC PUB CO	Dry/Plugged	11,136	11,141	3,157	9,057	6.29
72700	MFG REC PUB CO	Dry/Plugged	10,148	10,152	3,157	9,057	6.29
82769	MANUFACTURING RECORD PUB CO	Dry/Plugged	10,057	10,063	3,265	9,168	6.29
213809	PAR PZ RAB SU;LL&E	Shut-In/TA	9,886	9,898	3,097	8,938	6.29
213809	PAR PZ RAB SU;LL&E	Shut-In/TA	9,886	10,213	3,097	8,938	6.29
156920	LL&E PARADIS	Active Oil/Gas	10,965	10,973	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,944	10,957	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,841	10,851	3,097	8,938	6.30

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
156920	LL&E PARADIS	Active Oil/Gas	10,800	10,810	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,686	10,726	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,191	10,213	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	11,246	11,353	3,097	8,938	6.30
123512	LL&E PARADIS	Dry/Plugged	10,214	10,224	3,097	8,938	6.31
124355	PAR PZ RA-B SU	Dry/Plugged	9,922	9,940	3,097	8,938	6.31
121543	PAR PZ RA-B SU	Dry/Plugged	9,933	9,954	3,097	8,938	6.31
28525	PAR PZ RA-B SU	Dry/Plugged	10,211	10,238	3,013	8,690	6.32
120720	LL&E PARADIS	Active Oil/Gas	11,514	11,584	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,490	9,496	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,878	9,890	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	10,212	10,224	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,950	9,966	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	10,916	10,948	3,145	8,940	6.34
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	9,974	9,984	3,157	9,057	6.36
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	10,198	10,210	3,157	9,057	6.36
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	9,680	9,700	3,157	9,057	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,922	9,970	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,304	9,336	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,922	9,932	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,262	9,268	3,054	8,763	6.36
121156	LL&E PARADIS	Active Oil/Gas	10,385	10,404	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,960	9,970	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,262	9,294	3,054	8,763	6.36
107670	PAR PZ RAB SU;LL&E	Shut-In/TA	9,962	9,972	3,054	8,763	6.37
107670	PAR PZ RAB SU;LL&E	Shut-In/TA	10,045	10,056	3,054	8,763	6.37
124058	LL&E PARADIS	Active Oil/Gas	10,946	10,970	3,054	8,763	6.37
114075	PAR PZ RAB SU;LL&E	Dry/Plugged	9,882	9,892	3,145	8,940	6.38
114075	PAR PZ RAB SU;LL&E	Dry/Plugged	9,670	9,700	3,145	8,940	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,886	9,898	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,203	10,214	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,924	9,934	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,107	10,117	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,107	10,121	3,097	8,938	6.38
115628	LL&E PARADIS	Dry/Plugged	10,206	10,234	3,097	8,938	6.38
116527	PAR PZ RA-BSU;LL&E	Dry/Plugged	9,930	9,946	3,097	8,938	6.38
76313	PARADIS OIL UNIT NO H9	Dry/Plugged	10,081	10,088	3,157	9,057	6.41
27946	PARADIS SWD SYS #1	Active Injector	10,108	10,125	3,157	9,057	6.41
28671	LL&E PARADIS	Dry/Plugged	10,144	10,155	3,145	8,940	6.44
110984	LL & E PARADIS	Dry/Plugged	11,466	11,550	3,145	8,940	6.44

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
28671	LL&E PARADIS	Dry/Plugged	10,114	10,155	3,145	8,940	6.44
27198	PAR 1000 NAG RA SU	Dry/Plugged	9,969	9,989	3,013	8,690	6.47
27685	LL&E PARADIS	Dry/Plugged	10,340	10,356	3,013	8,690	6.47
27308	PAR PZ RAB SU;LL&E	Shut-In/TA	10,035	10,042	3,054	8,763	6.48
136931	LL&E PARADIS	Shut-In/TA	10,202	10,212	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,244	10,252	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,840	10,864	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,986	11,010	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,700	10,718	3,145	8,940	6.50
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	11,597	11,680	3,054	8,763	6.51
114911	LL&E PARADIS	Shut-In/TA	10,984	11,010	3,054	8,763	6.51
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	11,504	11,608	3,054	8,763	6.51
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	9,948	9,960	3,054	8,763	6.51
124384	PAR PZ RA-B SU	Dry/Plugged	10,012	10,018	3,054	8,763	6.53
27857	MFG REC PUB CO	Shut-In/TA	10,026	10,034	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,058	10,068	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,003	10,026	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	9,439	9,449	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,057	10,069	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	9,723	9,727	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,074	10,076	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,057	10,120	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,095	10,120	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	9,116	9,182	3,157	9,057	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,961	9,970	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,108	10,117	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,574	10,640	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,254	11,286	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,434	11,534	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,434	11,462	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,338	10,344	3,145	8,940	6.54
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	11,268	11,318	3,145	8,940	6.55
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	10,178	10,190	3,145	8,940	6.55
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	10,048	10,053	3,145	8,940	6.55
130830	PAR PZ RAB SU;MCDONALD	Active Oil/Gas	9,964	9,974	3,145	8,940	6.57

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
130830	PAR PZ RAB SU;MCDONALD	Active Oil/Gas	9,736	9,777	3,145	8,940	6.57
123535	LL&E PARADIS	Dry/Plugged	10,182	10,190	3,054	8,763	6.61
110313	LL&E PARADIS	Shut-In/TA	11,484	11,494	3,048	8,673	6.64
112298	LL&E PARADIS	Dry/Plugged	9,940	9,950	3,048	8,673	6.64
27333	LL&E PARADIS	Dry/Plugged	10,294	10,307	3,013	8,690	6.65
77629	PAR 9900 NAG RA SU;LL&E	Dry/Plugged	9,934	9,972	3,013	8,690	6.65
26189	PAR PZ RAB SU;LL&E	Shut-In/TA	10,112	10,122	3,048	8,673	6.65
132201	LL&E PARADIS	Dry/Plugged	9,508	9,514	3,145	8,940	6.66
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,000	10,010	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,450	10,463	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,812	10,827	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,051	10,065	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,032	10,046	3,145	8,940	6.67
101756	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,370	9,420	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,668	9,700	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,793	10,832	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,306	11,358	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,072	10,082	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,456	10,462	3,054	8,763	6.68
27883	LL&E PARADIS	Dry/Plugged	9,582	9,590	3,054	8,763	6.68
111053	10000 NAG RA SUC;LL&E	Dry/Plugged	9,812	9,820	3,054	8,763	6.68
126205	PAR 11800 NAG RA SU;LL&E	Shut-In/TA	11,434	11,529	3,145	8,940	6.73
127151	PAR 11500 RC SU;LL&E	Shut-In/TA	11,268	11,294	3,145	8,940	6.73
126205	PAR 11800 NAG RA SU;LL&E	Shut-In/TA	11,499	11,529	3,145	8,940	6.73
225160	LL&E PARADIS	Shut-In/TA	11,823	11,829	3,145	8,940	6.74
225160	LL&E PARADIS	Shut-In/TA	11,939	11,956	3,145	8,940	6.74
27095	PAR PZ RA B SU;LL&E	Dry/Plugged	9,968	9,976	3,111	8,795	6.75
27095	PAR PZ RA B SU;LL&E	Dry/Plugged	9,320	9,370	3,111	8,795	6.75
126271	LL&E PARADIS	Active Oil/Gas	11,330	11,422	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,782	10,830	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,782	10,820	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	11,521	11,551	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,038	10,090	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,002	10,090	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,070	10,820	3,111	8,795	6.80

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
110982	PAR 10000 NAG RU SU;LL & E	Dry/Plugged	9,972	10,026	3,048	8,673	6.82
27199	LL & E-PARADIS	Dry/Plugged	10,280	10,310	3,048	8,673	6.82
110979	LL & E PARADIS	Dry/Plugged	9,894	9,924	3,048	8,673	6.83
24867	PAR PZ RA B SU;LL&E	Dry/Plugged	10,122	10,142	3,048	8,673	6.83
26188	PAR PZ RAB SU;LL&E	Shut-In/TA	10,054	10,060	3,111	8,795	6.88
110981	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,384	9,446	3,111	8,795	6.88
139602	PAR PZ RAB SU;LL&E	Dry/Plugged	10,285	10,309	3,048	8,673	6.89
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	11,472	11,486	3,048	8,673	6.92
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	10,318	10,338	3,048	8,673	6.92
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	10,994	11,004	3,048	8,673	6.92
110980	LL & E PARADIS	Dry/Plugged	10,002	10,032	3,048	8,673	7.00
25451	LL&E PARADIS	Dry/Plugged	10,252	10,266	3,048	8,673	7.00
110983	LL & E PARADIS	Dry/Plugged	10,092	10,116	3,019	8,578	7.00
27332	LL&E PARADIS	Dry/Plugged	10,330	10,356	3,019	8,578	7.00
139592	PAR PZ RA-B SU	Dry/Plugged	10,366	10,373	3,048	8,673	7.10
49934	J B LEVERT LAND CO	Dry/Plugged	10,924	10,940		8,460	8.22
216770	12200 RA SUA;M L MANN ETAL	Dry/Plugged	13,342	13,347		8,729	8.75
69983	WATERFORD OIL CO	Dry/Plugged	10,001	10,007		8,798	8.77
68215	WATERFORD OIL COMPANY	Dry/Plugged	10,044	10,046		8,798	8.77
66030	E P BRADY SWD	Unable to Locate	9,942	9,948		8,798	8.82
156014	BRADY RA SUA;GOZAN ET AL	Dry/Plugged	9,995	9,997		8,798	8.88
156014	BRADY RA SUA;GOZAN ET AL	Dry/Plugged	9,940	9,948		8,798	8.88
156014	BRADY RA SUA;GOZAN ET AL	Dry/Plugged	9,941	9,947		8,798	8.88

1.11.8 Active Perforations Near the Area Boundary

A search was performed to identify any active wells within 5 mi of the centroid of the area boundary. A total of 88 active wells were found, which are listed in Table 1-23. There are 12 active producing wells located less than 2.25 mi away from the centroid. Of these, 10 active wells have perforations below the deepest lower confining zone (10,135 ft). There are two active injector wells located within the proposed injection zone: LYDIA B SIMONEAUX ET AL SWD (SN 68811) is located 2.02 mi from the area boundary centroid, and LYDIA B SIMONEAUX ET AL SWD (SN 72239) is located 2.22 mi from the area boundary centroid.

Table 1-23 – Active oil and gas wells within 5 mi of the area boundary.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	9,665	9,673	2,959	8,800	5.72
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	10,201	10,210	2,959	8,800	5.72
28027	9700 RA VUA;C V SINGLETON	Active Oil/Gas	9,666	9,673	2,959	8,800	5.72
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,610	8,630	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,250	8,258	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,862	8,885	3,097	9,024	5.51
34197	8700 NAG RB SUA;SR&P	Active Oil/Gas	8,877	8,885	3,097	9,024	5.51
36302	LL&E PARADIS	Active Oil/Gas	9,542	9,552	3,008	8,780	6.23
36302	LL&E PARADIS	Active Oil/Gas	9,793	9,798	3,008	8,780	6.23
36302	LL&E PARADIS	Active Oil/Gas	9,986	9,998	3,008	8,780	6.23
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,068	11,074	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,106	11,214	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,204	11,214	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,246	11,256	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,268	11,274	3,372	9,417	2.02
222844	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	11,300	11,310	3,372	9,417	2.02
224366	49 R203 SUA;SR&P	Active Oil/Gas	7,134	7,136	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	7,732	7,736	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	8,162	8,172	3,017	8,910	5.82
224366	49 R203 SUA;SR&P	Active Oil/Gas	8,352	8,356	3,017	8,910	5.82
237079	C E GHEENS	Active Oil/Gas	7,310	7,345	2,638		4.42

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
237079	C E GHEENS	Active Oil/Gas	7,736	7,749	2,638		4.42
250321	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,500	12,544	3,576	10,106	1.71
250321	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,554	12,600	3,576	10,106	1.71
250809	SIMONEAUX FAMILY LAND LLC A	Active Oil/Gas	13,774	13,940	3,576	10,106	1.71
250810	SIMONEAUX FAMILY LAND LLC	Active Oil/Gas	12,403	12,422	3,576	10,106	1.71
250903	EMC FEE	Active Oil/Gas	12,236	12,266	3,642	10,135	4.15
250965	EMC FEE	Active Oil/Gas	13,428	13,530	3,642	10,135	4.15
250965	EMC FEE	Active Oil/Gas	13,578	13,619	3,642	10,135	4.15
251823	EMC FEE	Active Oil/Gas	11,260	11,300	3,642	10,135	4.15
251823	EMC FEE	Active Oil/Gas	11,364	11,462	3,642	10,135	4.15
251823	EMC FEE	Active Oil/Gas	11,410	11,462	3,642	10,135	4.15
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,982	9,998	3,153	9,029	5.84
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	8,950	8,960	3,153	9,029	5.84
27325	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,656	9,666	3,153	9,029	5.84
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	10,014	10,044	3,197	9,137	5.42
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	10,378	10,384	3,197	9,137	5.42
28758	PZ SU262;W E DUFRENE	Active Oil/Gas	8,644	8,660	3,197	9,137	5.42
52926	BDA 5500 SU;DELTA SECURITIES	Active Oil/Gas	5,456	5,462	3,222	9,882	3.37
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,072	10,082	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,456	10,462	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,306	11,358	3,054	8,763	6.68

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,793	10,832	3,054	8,763	6.68
70816	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,668	9,700	3,054	8,763	6.68
113302	ST CHARLES LAND CO A RAB	Active Oil/Gas	5,446	5,454	3,328	9,891	3.09
113789	BDA 5000 RA SU;ST CHAS LD CO A	Active Oil/Gas	4,998	5,002	3,328	9,891	3.07
113789	BDA 5000 RA SU;ST CHAS LD CO A	Active Oil/Gas	4,983	4,995	3,328	9,891	3.07
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,961	9,970	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,108	10,117	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,338	10,344	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,574	10,640	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,254	11,286	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,434	11,534	3,145	8,940	6.54
117248	PAR PZ RAB SU;LL&E	Active Oil/Gas	11,434	11,462	3,145	8,940	6.54
120055	DELTA SEC CO INC A	Active Oil/Gas	7,083	7,100	3,312	9,867	5.04
120055	DELTA SEC CO INC A	Active Oil/Gas	7,420	7,443	3,312	9,867	5.04
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,830	9,851	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,830	9,898	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,205	10,226	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,328	10,364	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	1,0058	10,070	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,839	9,853	3,097	8,938	6.13
124584	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,158	10,163	3,097	8,938	6.13

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
129753	DELTA SEC CO INC	Active Oil/Gas	6,620	6,640	3,199	9,781	5.61
130830	PAR PZ RAB SU;MCDONALD	Active Oil/Gas	9,964	9,974	3,145	8,940	6.57
130830	PAR PZ RAB SU;MCDONALD	Active Oil/Gas	9,736	9,777	3,145	8,940	6.57
135871	DELTA SEC CO INC	Active Oil/Gas	6,544	6,557	3,012	9,701	5.92
135871	DELTA SEC CO INC	Active Oil/Gas	6,525	6,540	3,012	9,701	5.92
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,850	9,874	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,858	9,874	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,064	10,074	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,708	10,770	3,097	8,938	6.07
138651	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,211	10,232	3,097	8,938	6.07
153301	PARADIS SUG;SR&P	Active Oil/Gas	9,972	10,002	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	9,990	10,002	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,842	10,900	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,194	10,222	3,153	9,029	5.66
153301	PARADIS SUG;SR&P	Active Oil/Gas	10,314	10,340	3,153	9,029	5.66
204745	C E GHEENS	Active Oil/Gas	7,816	7,924	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,856	7,924	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,760	7,766	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,798	7,826	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,800	7,802	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,808	7,814	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,820	7,826	2,638		4.45

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
204745	C E GHEENS	Active Oil/Gas	7,878	7,894	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,918	7,940	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	7,865	7,862	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,000	8,070	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,120	8,142	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,150	8,154	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,190	8,196	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,221	8,230	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,310	8,318	2,638		4.45
204745	C E GHEENS	Active Oil/Gas	8,297	8,307	2,638		4.45
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,231	10,288	3,372	9,417	2.07
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,275	10,288	3,372	9,417	2.07
207048	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,255	10,266	3,372	9,417	2.07
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,924	9,934	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	9,886	9,898	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,107	10,121	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,107	10,117	3,097	8,938	6.38
207505	PAR PZ RAB SU;LL&E	Active Oil/Gas	10,203	10,214	3,097	8,938	6.38
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,334	7,344	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,244	7,268	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,270	7,283	2,938	9,703	3.75

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,416	7,425	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,244	7,257	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,609	7,646	2,938	9,703	3.75
208324	BN G2 SUA;C E GHEENS	Active Oil/Gas	7,826	7,840	2,938	9,703	3.75
215258	C E GHEENS	Active Oil/Gas	7,858	7,870	2,638		4.48
215258	C E GHEENS	Active Oil/Gas	7,943	7,956	2,638		4.48
215258	C E GHEENS	Active Oil/Gas	7,998	8,046	2,638		4.48
215258	C E GHEENS	Active Oil/Gas	8,264	8,314	2,638		4.48
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,265	10,267	3,356	9,418	1.90
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,277	10,287	3,356	9,418	1.90
217145	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,270	10,274	3,356	9,418	1.90
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,958	9,964	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,984	9,992	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	9,972	9,980	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,155	10,191	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,155	10,175	3,153	9,029	5.83
217491	PZ RA SUH;MFG REC PUB CO	Active Oil/Gas	10,184	10,200	3,153	9,029	5.83
248482	DELTA SECURITIES CO INC	Active Oil/Gas	4,581	4,590	3,222	9,882	3.39
248482	DELTA SECURITIES CO INC	Active Oil/Gas	4,581	4,587	3,222	9,882	3.39
252221	DELTA SEC CO INC	Active Oil/Gas	5,274	5,279	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	5,485	5,492	3,108	9,220	5.98

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
252221	DELTA SEC CO INC	Active Oil/Gas	7,505	7,520	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	7,760	7,826	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	7,804	7,826	3,108	9,220	5.98
252221	DELTA SEC CO INC	Active Oil/Gas	6,410	6,456	3,108	9,220	5.98
252332	DELTA SEC CO INC	Active Oil/Gas	5,950	6,100	3,132	9,506	5.54
252351	DELTA SEC CO INC	Active Oil/Gas	4,356	4,364	3,108	9,220	5.93
252351	DELTA SEC CO INC	Active Oil/Gas	4,790	4,942	3,108	9,220	5.93
972303	WASTE DISPOSAL	Active Injector	7,046	7,206		8,367	7.58
972303	WASTE DISPOSAL	Active Injector	7,074	7,340		8,367	7.58
972604	WASTE DISPOSAL	Active Injector	7,062	7,305		8,461	7.32
972604	WASTE DISPOSAL	Active Injector	7,012	7,321		8,461	7.32
972604	WASTE DISPOSAL	Active Injector	8,040	8,355		8,461	7.32
972768	WASTE DISPOSAL	Active Injector	7,141	7,317		8,461	7.22
972768	WASTE DISPOSAL	Active Injector	7,015	7,533		8,461	7.22
972952	WASTE DISPOSAL	Active Injector	7,117	7,326		8,461	7.26
973696	WASTE DISPOSAL	Active Injector	7,122	7,319		8,461	7.16
975168	WASTE DISPOSAL	Active Injector	7,176	7,360		8,429	7.07
27422	SR&P SWD	Active Injector	5,700	5,710	3,008	8,780	5.95
27422	SR&P SWD	Active Injector	9,826	9,856	3,008	8,780	5.95
27422	SR&P SWD	Active Injector	10,100	10,104	3,008	8,780	5.95
27422	SR&P SWD	Active Injector	9,902	9,910	3,008	8,780	5.95
27543	LL&E SWD	Active Injector	2,920	3,000	3,008	8,780	6.27

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
27543	LL&E SWD	Active Injector	2,960	2,980	3,008	8,780	6.27
27543	LL&E SWD	Active Injector	10,036	10,045	3,008	8,780	6.27
27946	PARADIS SWD SYS #1	Active Injector	2,993	3,370	3,157	9,057	6.41
27946	PARADIS SWD SYS #1	Active Injector	3,294	3,370	3,157	9,057	6.41
27946	PARADIS SWD SYS #1	Active Injector	3,320	3,370	3,157	9,057	6.41
27946	PARADIS SWD SYS #1	Active Injector	10,108	10,125	3,157	9,057	6.41
28186	ARMSTRONG SWD	Active Injector	5,090	5,110	3,008	8,780	6.18
28186	ARMSTRONG SWD	Active Injector	5,295	5,320	3,008	8,780	6.18
28186	ARMSTRONG SWD	Active Injector	9,927	10,002	3,008	8,780	6.18
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,865	2,022	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,750	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,792	1,842	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,750	1,780	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,865	1,880	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,972	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,135	2,820	3,222	9,882	3.29
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,770	2,820	3,222	9,882	3.29

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
48525	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	5,285	5,294	3,222	9,882	3.29
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	1,980	2,170	3,222	9,882	3.21
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	2,120	2,170	3,222	9,882	3.21
49818	BAYOU DES ALLEMANDS SWD SYSTEM	Active Injector	4,461	4,471	3,222	9,882	3.21
55112	DELTA SEC CO INC SWD	Active Injector	2,786	2,820	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	0	0	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	2,890	2,920	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	3,160	3,640	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	3,500	3,640	3,199	9,781	5.55
55112	DELTA SEC CO INC SWD	Active Injector	6,618	6,649	3,199	9,781	5.55
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	6,590	6,610	3,372	9,417	2.02
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	10,953	10,991	3,372	9,417	2.02
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	11,000	11,020	3,372	9,417	2.02
68811	LYDIA B SIMONEAUX ET AL SWD	Active Injector	10,884	10,894	3,372	9,417	2.02
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	2,650	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,040	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,710	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	4,996	5,230	3,282	9,266	2.22

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,054	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,160	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	5,210	5,230	3,282	9,266	2.22
72239	LYDIA B SIMONEAUX ET AL SWD	Active Injector	12,168	12,190	3,282	9,266	2.22
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	2,952	2,970	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	2,952	2,960	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,150	3,282	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,462	3,562	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	9,888	9,908	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	9,442	9,451	3,097	8,938	5.92
114768	SUNSET REALTY & PLTG CO SWD	Active Injector	3,370	3,566	3,097	8,938	5.92
132509	SR&P SWD	Active Injector	6,010	6,030	3,017	8,910	5.92
132509	SR&P SWD	Active Injector	10,828	10,912	3,017	8,910	5.92
132509	SR&P SWD	Active Injector	10,986	10,998	3,017	8,910	5.92
207203	C E GHEENS SWD	Active Injector	2,727	2,747	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	3,909	3,969	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	4,160	4,270	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	8,105	8,116	2,646	9,470	4.42
207203	C E GHEENS SWD	Active Injector	8,298	8,305	2,646	9,470	4.42
970034	C E GHEENS SWD	Active Injector	1,190	1,276	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,236	1,276	3,419		3.68

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
970034	C E GHEENS SWD	Active Injector	1,400	1,490	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,892	1,969	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,892	1,920	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,700	1,710	3,419		3.68
970034	C E GHEENS SWD	Active Injector	1,949	1,969	3,419		3.68
970128	LL&E SWD	Active Injector	1,970	2,086	3,008	8,780	6.24
970128	LL&E SWD	Active Injector	2,246	2,286	3,008	8,780	6.24
970128	LL&E SWD	Active Injector	2,266	2,286	3,008	8,780	6.24
76172	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,881	10,902	3,356	9,418	1.71
84594	C E GHEENS	Active Oil/Gas	7,590	7,596	2,638		4.44
85094	SUNSET REALTY & PLANTING CO	Active Oil/Gas	10,004	10,012	3,097	9,024	5.51
85094	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,970	9,978	3,097	9,024	5.51
85991	LYDIA B SIMONEAUX ET AL	Active Oil/Gas	10,845	10,875	3,372	9,417	1.94
86867	C E GHEENS	Active Oil/Gas	7,766	7,770	2,646	9,470	4.30
90519	C E GHEENS	Active Oil/Gas	7,758	7,765	2,646	9,470	4.40
101758	LL&E PARADIS	Active Oil/Gas	9,332	9,356	3,008	8,780	6.23
105573	DELTA SECURITIES CO INC	Active Oil/Gas	5,278	5,284	3,222	9,882	3.22
108601	DELTA SECURITIES CO INC	Active Oil/Gas	5,075	5,084	3,222	9,882	3.19
108647	DELTA SEC CO INC	Active Oil/Gas	4,070	4,076	3,160	9,527	5.36
109441	DELTA SEC CO INC	Active Oil/Gas	5,697	5,710	2,982	9,365	5.98
110976	CLARK V SINGLETON	Active Oil/Gas	9,856	9,900	2,959	8,800	5.72

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
110978	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,671	9,702	3,008	8,780	5.95
111012	SUNSET REALTY & PLANTING CO	Active Oil/Gas	10,236	10,258	3,017	8,910	5.81
113257	LL&E PARADIS	Active Oil/Gas	9,980	10,004	3,157	9,057	6.24
114452	WATERFORD OIL CO	Active Oil/Gas	11,160	11,180	3,642	10,135	4.17
115178	LL&E PARADIS	Active Oil/Gas	10,171	10,190	3,097	8,938	6.13
116118	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,687	9,710	3,008	8,780	5.94
116629	DELTA SEC CO INC	Active Oil/Gas	5,666	5,677	3,132	9,506	5.76
120720	LL&E PARADIS	Active Oil/Gas	11,514	11,584	3,145	8,940	6.34
121156	LL&E PARADIS	Active Oil/Gas	10,385	10,404	3,054	8,763	6.36
124058	LL&E PARADIS	Active Oil/Gas	10,946	10,970	3,054	8,763	6.37
124470	LL&E PARADIS	Active Oil/Gas	10,758	10,788	3,153	9,029	5.95
125419	C E GHEENS	Active Oil/Gas	8,057	8,087	2,646	9,470	4.40
126271	LL&E PARADIS	Active Oil/Gas	11,330	11,422	3,111	8,795	6.80
133566	SUNSET REALTY & PLANTING CO	Active Oil/Gas	9,951	9,964	3,017	8,910	5.92
156920	LL&E PARADIS	Active Oil/Gas	10,191	10,213	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,686	10,726	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,800	10,810	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,841	10,851	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,944	10,957	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	10,965	10,973	3,097	8,938	6.30
156920	LL&E PARADIS	Active Oil/Gas	11,246	11,353	3,097	8,938	6.30

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (mi)
217287	MFG REC PUB CO	Active Oil/Gas	10,294	10,297	3,153	9,029	5.83
217287	MFG REC PUB CO	Active Oil/Gas	13,309	13,316	3,153	9,029	5.83
217287	MFG REC PUB CO	Active Oil/Gas	10,302	10,305	3,153	9,029	5.83
252330	DELTA SEC CO INC	Active Oil/Gas	5,785	5,929	3,132	9,506	5.58
252331	DELTA SEC CO INC	Active Oil/Gas	5,614	5,730	3,108	9,220	5.98
252352	DELTA SEC CO INC	Active Oil/Gas	4,575	4,722	3,108	9,220	5.93
55112	DELTA SEC CO INC SWD	Active Injector	0	0	3,199	9,781	5.55

1.11.9 Shut-in and Temporarily Abandoned Wells Near the Area Boundary

A search was conducted for shut-in and temporarily abandoned wells with perforations within 5 mi of the area boundary and subsequently reviewed. A total of 142 wells were identified and are listed in Table 1-24.

Table 1-24 – Shut-in and temporarily abandoned wells with perforations within 5 mi of the area boundary.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	8,720	8,740	3,218	9,156	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,015	9,023	3,218	9,156	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,355	9,366	3,218	9,156	5.59
28539	8700 RC-2 SUA;J BRANCH	Shut-In/TA	9,015	9,020	3,218	9,156	5.59
32657	9900 NAG RA SUK;SR&P	Shut-In/TA	9,628	9,646	3,097	9,024	5.28
33253	10000 RC SUF;SR&P	Shut-In/TA	9,660	9,670	3,197	9,137	5.34
33253	10000 RC SUF;SR&P	Shut-In/TA	10,043	10,047	3,197	9,137	5.34
73600	JOSEPH DAMICO	Shut-In/TA	9,864	9,893	3,348	9,273	5.57

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
101756	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,370	9,420	3,054	8,763	6.68
110313	LL&E PARADIS	Shut-In/TA	11,484	11,494	3,048	8,673	6.64
110981	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,384	9,446	3,111	8,795	6.88
114074	LL&E PARADIS	Shut-In/TA	9,570	9,592	3,097	8,938	6.13
114911	LL&E PARADIS	Shut-In/TA	10,984	11,010	3,054	8,763	6.51
118954	LL&E PARADIS	Shut-In/TA	8,470	8,490	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,490	9,496	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,878	9,890	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	10,212	10,224	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	9,950	9,966	3,145	8,940	6.34
118954	LL&E PARADIS	Shut-In/TA	10,916	10,948	3,145	8,940	6.34
123251	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,224	9,248	3,097	8,938	6.18
123251	PAR 9500 NAG RA SU;LL&E	Shut-In/TA	9,438	9,443	3,097	8,938	6.18
126205	PAR 11800 NAG RA SU;LL&E	Shut-In/TA	11,434	11,529	3,145	8,940	6.73
126205	PAR 11800 NAG RA SU;LL&E	Shut-In/TA	11,499	11,529	3,145	8,940	6.73
127151	PAR 11500 RC SU;LL&E	Shut-In/TA	11,268	11,294	3,145	8,940	6.73
129307	PAR 9500 NAG RA SU;SR&P	Shut-In/TA	9,294	9,308	3,097	9,024	5.28
225160	LL&E PARADIS	Shut-In/TA	11,823	11,829	3,145	8,940	6.74
225160	LL&E PARADIS	Shut-In/TA	11,939	11,956	3,145	8,940	6.74
26186	C E GHEENS	Shut-In/TA	10,147	10,161	3,419		3.74
26186	C E GHEENS	Shut-In/TA	10,290	10,300	3,419		3.74
26186	C E GHEENS	Shut-In/TA	10,198	10,252	3,419		3.74

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
27686	PAR PZ RAB SU;SR&P	Shut-In/TA	9,959	9,970	3,008	8,780	5.95
27686	PAR PZ RAB SU;SR&P	Shut-In/TA	9,671	9,702	3,008	8,780	5.95
28136	U 9000 RE SUA;EDWARD DANNEL	Shut-In/TA	8,963	8,998	3,218	9,156	5.66
28136	U 9000 RE SUA;EDWARD DANNEL	Shut-In/TA	9,017	9,028	3,218	9,156	5.66
33967	BDA 17 RA SU;GHEENS	Shut-In/TA	8,130	8,164	2,638		4.44
72110	10000 RC SUB;J DAMICO	Shut-In/TA	10,010	10,022	3,348	9,273	5.57
85523	C E GHEENS	Shut-In/TA	7,896	7,912	2,646	9,470	4.35
85523	C E GHEENS	Shut-In/TA	7,904	7,912	2,646	9,470	4.35
85523	C E GHEENS	Shut-In/TA	8,039	8,045	2,646	9,470	4.35
107966	D RC SUA;DELTA SECURITIES	Shut-In/TA	5,516	5,524	3,222	9,882	3.25
107966	D RC SUA;DELTA SECURITIES	Shut-In/TA	4,864	4,874	3,222	9,882	3.25
205801	C E GHEENS	Shut-In/TA	7,473	7,576	2,638		4.33
205801	C E GHEENS	Shut-In/TA	7,469	7,576	2,638		4.33
205801	C E GHEENS	Shut-In/TA	7,469	7,477	2,638		4.33
205801	C E GHEENS	Shut-In/TA	7,042	7,061	2,638		4.33
205801	C E GHEENS	Shut-In/TA	7,164	7,178	2,638		4.33
205801	C E GHEENS	Shut-In/TA	7,182	7,192	2,638		4.33
195630	C E GHEENS	Shut-In/TA	0	0	2,962		3.74
26195	SARAH SIMMS MALLORY	Shut-In/TA	8,794	8,830	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,150	9,157	3,218	9,156	5.75

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,600	9,612	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,580	9,593	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	10,081	10,127	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	10,010	10,028	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,600	9,608	3,218	9,156	5.75
26195	SARAH SIMMS MALLORY	Shut-In/TA	9,993	10,019	3,218	9,156	5.75
27857	MFG REC PUB CO	Shut-In/TA	9,116	9,182	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	9,439	9,449	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	9,723	9,727	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,003	10,026	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,026	10,034	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,058	10,068	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,057	10,069	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,074	10,076	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,057	10,120	3,157	9,057	6.54
27857	MFG REC PUB CO	Shut-In/TA	10,095	10,120	3,157	9,057	6.54
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,748	9,784	3,097	9,024	5.54
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	10,080	10,090	3,097	9,024	5.54
33608	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,822	9,828	3,097	9,024	5.54
56712	WATERFORD OIL CO	Shut-In/TA	11,449	11,534	3,642	10,135	4.17
71015	NETHERLANDS CORP	Shut-In/TA	11,522	11,534	3,388	10,108	4.61
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,460	9,462	3,017	8,910	5.81

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,464	9,478	3,017	8,910	5.81
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	9,864	9,876	3,017	8,910	5.81
112493	PAR 9900 NAG RA SU;SR&P	Shut-In/TA	10,820	10,840	3,017	8,910	5.81
115207	PAR 10000 NAG RA SU;LL&E	Shut-In/TA	9,962	9,966	3,097	8,938	6.24
115207	PAR 10000 NAG RA SU;LL&E	Shut-In/TA	9,627	9,660	3,097	8,938	6.24
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	8,374	8,378	3,097	9,024	5.60
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	10,010	10,028	3,097	9,024	5.60
136833	SUNSET REALTY & PLANTING CO	Shut-In/TA	9,582	9,626	3,097	9,024	5.60
142607	DELTA SEC CO INC	Shut-In/TA	2,308	2,318	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	8,223	8,232	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	4,316	4,326	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	7,954	7,964	3,160	9,527	5.28
142607	DELTA SEC CO INC	Shut-In/TA	7,729	7,733	3,160	9,527	5.28
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	12,106	12,130	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	12,277	12,282	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	12,277	12,304	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	11,104	11,120	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	11,137	11,165	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	11,755	11,778	3,285	9,163	2.59
142882	SIM 10 RA SUA; SIMONEAU X	Shut-In/TA	11,878	11,890	3,285	9,163	2.59
165206	WATERFORD OIL CO	Shut-In/TA	10,986	10,990	3,605	10,093	4.31

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
165206	WATERFORD OIL CO	Shut-In/TA	10,766	10,776	3,605	10,093	4.31
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,294	10,303	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,362	10,368	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,351	10,357	3,489	9,997	2.84
189297	10400 RA SUB;ST CHAS LD CO	Shut-In/TA	10,264	10,330	3,489	9,997	2.84
205598	C E GHEENS	Shut-In/TA	7,222	7,228	2,962		3.82
205598	C E GHEENS	Shut-In/TA	7,244	7,280	2,962		3.82
205598	C E GHEENS	Shut-In/TA	7,330	7,352	2,962		3.82
205598	C E GHEENS	Shut-In/TA	7,478	7,500	2,962		3.82
207742	BIG N 1 RA SUA;SL 348	Shut-In/TA	6,869	6,892	2,938	9,703	3.70
207742	BIG N 1 RA SUA;SL 348	Shut-In/TA	6,848	6,866	2,938	9,703	3.70
208093	C E GHEENS	Shut-In/TA	7,197	7,214	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,223	7,227	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,263	7,265	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,530	7,571	2,938	9,703	3.91
208093	C E GHEENS	Shut-In/TA	7,638	7,646	2,938	9,703	3.91
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	8,964	8,970	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	8,986	9,002	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,051	10,104	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,078	10,104	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	10,603	10,614	3,153	9,029	5.69
224550	U 9000 RC-3 SUA;ROBERT SIMS	Shut-In/TA	11,166	11,170	3,153	9,029	5.69

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
228897	DELTA SEC CO INC	Shut-In/TA	7,678	7,967	3,199	9,781	5.39
229744	DELTA SEC CO INC	Shut-In/TA	6,988	6,994	3,312	9,867	5.02
229744	DELTA SEC CO INC	Shut-In/TA	8,376	8,430	3,312	9,867	5.02
229744	DELTA SEC CO INC	Shut-In/TA	8,516	8,608	3,312	9,867	5.02
251069	SIMONEAUX	Shut-In/TA	10,978	10,988	3,489	9,997	2.80
251069	SIMONEAUX	Shut-In/TA	11,440	11,464	3,489	9,997	2.80
252220	DELTA SEC CO INC	Shut-In/TA	5,490	5,495	3,132	9,506	5.58
252220	DELTA SEC CO INC	Shut-In/TA	5,990	6,160	3,132	9,506	5.58
252300	DELTA SEC CO INC	Shut-In/TA	7,551	7,557	3,108	9,220	5.95
252300	DELTA SEC CO INC	Shut-In/TA	7,630	7,666	3,108	9,220	5.95
26188	PAR PZ RAB SU;LL&E	Shut-In/TA	10,054	10,060	3,111	8,795	6.88
26189	PAR PZ RAB SU;LL&E	Shut-In/TA	10,112	10,122	3,048	8,673	6.65
27308	PAR PZ RAB SU;LL&E	Shut-In/TA	10,035	10,042	3,054	8,763	6.48
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,032	10,046	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,051	10,065	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,812	10,827	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,450	10,463	3,145	8,940	6.67
27448	PARADIS RA SUB;MFG REC PUB CO	Shut-In/TA	10,000	10,010	3,145	8,940	6.67
28307	DELTA SEC CO INC	Shut-In/TA	6,450	6,470	3,132	9,506	5.80
28307	DELTA SEC CO INC	Shut-In/TA	5,680	5,690	3,132	9,506	5.80
28576	DELTA SEC CO INC	Shut-In/TA	5,430	5,439	2,982	9,365	6.01

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
28576	DELTA SEC CO INC	Shut-In/TA	5,389	5,439	2,982	9,365	6.01
29704	DELTA SEC CO INC	Shut-In/TA	7,990	7,995	3,108	9,220	5.67
29704	DELTA SEC CO INC	Shut-In/TA	7,601	7,644	3,108	9,220	5.67
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,946	9,954	3,157	9,057	6.24
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,980	10,000	3,157	9,057	6.24
29909	PAR PZ RAB SU;LL&E	Shut-In/TA	9,979	9,984	3,157	9,057	6.24
37799	DELTA SEC CO INC	Shut-In/TA	4,642	4,664	3,132	9,506	5.88
37799	DELTA SEC CO INC	Shut-In/TA	4,649	4,665	3,132	9,506	5.88
37799	DELTA SEC CO INC	Shut-In/TA	4,649	4,655	3,132	9,506	5.88
38770	DELTA SEC CO INC	Shut-In/TA	5,392	5,437	2,982	9,365	6.12
40051	DELTA SEC CO INC	Shut-In/TA	4,596	4,604	3,108	9,220	6.01
40051	DELTA SEC CO INC	Shut-In/TA	5,626	5,662	3,108	9,220	6.01
40051	DELTA SEC CO INC	Shut-In/TA	5,376	5,438	3,108	9,220	6.01
43987	DELTA SEC CO INC	Shut-In/TA	5,905	5,911	3,199	9,781	5.32
43987	DELTA SEC CO INC	Shut-In/TA	6,842	6,911	3,199	9,781	5.32
43987	DELTA SEC CO INC	Shut-In/TA	6,723	6,740	3,199	9,781	5.32
45492	DELTA SEC CO INC	Shut-In/TA	6,650	6,656	3,012	9,701	5.65
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,196	5,204	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,300	5,306	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,331	5,334	3,222	9,882	3.32
47202	DELTA SECURITIES CO INC	Shut-In/TA	5,520	5,526	3,222	9,882	3.32
47354	DELTA SEC CO INC	Shut-In/TA	4,044	4,051	3,160	9,527	5.39

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
47354	DELTA SEC CO INC	Shut-In/TA	4,869	4,876	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	7,190	7,209	3,160	9,527	5.39
47354	DELTA SEC CO INC	Shut-In/TA	5,814	5,850	3,160	9,527	5.39
47614	DELTA SEC CO INC	Shut-In/TA	7,386	7,396	3,225	9,679	5.35
48021	DELTA SEC CO INC	Shut-In/TA	4,432	4,444	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,178	7,186	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,456	7,484	3,160	9,527	5.30
48021	DELTA SEC CO INC	Shut-In/TA	7,362	7,386	3,160	9,527	5.30
48225	DELTA SEC CO INC	Shut-In/TA	5,339	5,362	3,160	9,527	5.21
48225	DELTA SEC CO INC	Shut-In/TA	7,923	7,344	3,160	9,527	5.21
49301	DELTA SEC CO INC	Shut-In/TA	7,408	7,413	3,160	9,527	5.34
49982	DELTA SEC CO INC	Shut-In/TA	3,819	3,826	3,160	9,527	5.39
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,261	10,271	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,296	10,316	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,882	10,900	3,372	9,417	1.92
50504	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,185	11,200	3,372	9,417	1.92
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,002	11,016	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,881	10,896	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	11,000	11,020	3,356	9,418	1.72
51104	LYDIA B SIMONEAUX ET AL	Shut-In/TA	10,911	10,924	3,356	9,418	1.72
63196	DELTA SEC CO INC	Shut-In/TA	6,188	6,200	3,199	9,781	5.67
63196	DELTA SEC CO INC	Shut-In/TA	6,575	6,584	3,199	9,781	5.67

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
63982	DELTA SEC CO INC A	Shut-In/TA	7,301	7,337	3,199	9,781	5.36
63982	DELTA SEC CO INC A	Shut-In/TA	7,301	7,323	3,199	9,781	5.36
64666	DELTA SEC CO INC A	Shut-In/TA	7,021	7,030	3,199	9,781	5.41
65309	DELTA SEC CO INC	Shut-In/TA	5,658	5,773	3,160	9,527	5.68
65309	DELTA SEC CO INC	Shut-In/TA	5,750	5,757	3,160	9,527	5.68
65310	DELTA SEC CO INC A	Shut-In/TA	7,557	7,573	3,199	9,781	5.23
66725	DELTA SEC CO INC A	Shut-In/TA	6,977	6,995	3,199	9,781	5.58
69352	DELTA SEC CO INC A	Shut-In/TA	7,995	8,005	3,312	9,867	5.08
70134	DELTA SEC CO INC A	Shut-In/TA	7,433	7,441	3,312	9,867	5.02
70134	DELTA SEC CO INC A	Shut-In/TA	7,164	7,193	3,312	9,867	5.02
89728	C E GHEENS	Shut-In/TA	7,402	7,410	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,420	7,422	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,613	7,628	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,890	7,908	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	7,934	7,942	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	8,212	8,225	2,646	9,470	4.40
89728	C E GHEENS	Shut-In/TA	8,212	8,292	2,646	9,470	4.40
104652	DELTA SECURITIES CO INC	Shut-In/TA	4,408	4,418	3,222	9,882	3.22
104652	DELTA SECURITIES CO INC	Shut-In/TA	5,329	5,336	3,222	9,882	3.22
107281	DELTA SEC CO INC	Shut-In/TA	5,428	5,444	2982	9,365	6.08
107282	DELTA SEC CO INC	Shut-In/TA	6,663	6,673	3,199	9,781	5.46
107323	DELTA SEC CO INC	Shut-In/TA	7,400	7,456	3,160	9,527	5.35

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
107323	DELTA SEC CO INC	Shut-In/TA	5,181	5,188	3,160	9,527	5.35
107670	PAR PZ RAB SU;LL&E	Shut-In/TA	9,962	9,972	3,054	8,763	6.37
107670	PAR PZ RAB SU;LL&E	Shut-In/TA	10,045	10,056	3,054	8,763	6.37
107815	DELTA SEC CO INC	Shut-In/TA	7,208	7,214	3,160	9,527	5.31
107815	DELTA SEC CO INC	Shut-In/TA	7,361	7,385	3,160	9,527	5.31
108222	DELTA SEC CO INC	Shut-In/TA	5,080	5,095	2,982	9,365	5.95
108222	DELTA SEC CO INC	Shut-In/TA	5,098	5,110	2,982	9,365	5.95
108222	DELTA SEC CO INC	Shut-In/TA	5,377	5,384	2,982	9,365	5.95
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	9,948	9,960	3,054	8,763	6.51
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	11,597	11,680	3,054	8,763	6.51
112891	PAR PZ RAB SU;LL&E	Shut-In/TA	11,504	11,608	3,054	8,763	6.51
114894	M-1 RB VUA;SL 348	Shut-In/TA	6,588	6,596	2,938	9,703	3.66
115146	DELTA SEC CO INC	Shut-In/TA	5,386	5,459	3,132	9,506	5.79
115146	DELTA SEC CO INC	Shut-In/TA	3,248	3,280	3,132	9,506	5.79
115806	U X1 RA VUA;SL 348	Shut-In/TA	5,938	5,960	2,938	9,703	3.68
115806	U X1 RA VUA;SL 348	Shut-In/TA	5,978	5,982	2,938	9,703	3.68
116228	PAR PZ RAB SU;SR&P	Shut-In/TA	10,128	10,146	3,017	8,910	5.86
116228	PAR PZ RAB SU;SR&P	Shut-In/TA	9,926	9,936	3,017	8,910	5.86
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,922	9,970	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,922	9,932	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,262	9,268	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,262	9,294	3,054	8,763	6.36

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,960	9,970	3,054	8,763	6.36
120456	PAR PZ RAB SU;LL&E	Shut-In/TA	9,304	9,336	3,054	8,763	6.36
122066	DELTA SEC CO INC	Shut-In/TA	5,634	5,645	2,982	9,365	6.03
122066	DELTA SEC CO INC	Shut-In/TA	5,492	5,502	2,982	9,365	6.03
123691	LL&E PARADIS	Shut-In/TA	8,898	8,904	3,153	9,029	5.95
123691	LL&E PARADIS	Shut-In/TA	8,912	8,921	3,153	9,029	5.95
123691	LL&E PARADIS	Shut-In/TA	8,930	8,940	3,153	9,029	5.95
124223	DELTA SEC CO INC	Shut-In/TA	5,454	5,460	2,982	9,365	6.02
124223	DELTA SEC CO INC	Shut-In/TA	6,077	6,083	2,982	9,365	6.02
124223	DELTA SEC CO INC	Shut-In/TA	6,221	6,224	2,982	9,365	6.02
124502	DELTA SEC CO INC	Shut-In/TA	6,662	6,668	3,199	9,781	5.38
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,002	10,090	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,038	10,090	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,070	10,820	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,782	10,820	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	10,782	10,830	3,111	8,795	6.80
125740	PAR PZ RAB SU;LL&E	Shut-In/TA	11,521	11,551	3,111	8,795	6.80
125941	BDA 14-B RA SU;GHEENS	Shut-In/TA	7,896	7,906	2,646	9,470	4.40
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	10,048	10,053	3,145	8,940	6.55
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	10,178	10,190	3,145	8,940	6.55
128452	PARADIS RA SUD;MFG REC PUB CO	Shut-In/TA	11,268	11,318	3,145	8,940	6.55

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
129752	DELTA SEC CO INC	Shut-In/TA	5,471	5,481	3,132	9,506	5.93
129752	DELTA SEC CO INC	Shut-In/TA	6,477	6,490	3,132	9,506	5.93
129752	DELTA SEC CO INC	Shut-In/TA	6,425	6,432	3,132	9,506	5.93
129754	DELTA SEC CO INC	Shut-In/TA	7,471	7,477	3,160	9,527	5.35
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	9,680	9,700	3,157	9,057	6.36
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	10,198	10,210	3,157	9,057	6.36
132200	PAR PZ RAB SU;LL&E	Shut-In/TA	9,974	9,984	3,157	9,057	6.36
133621	DELTA SEC CO INC	Shut-In/TA	4,356	4,366	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	7,454	7,460	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,339	8,349	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,500	8,506	3,160	9,527	5.30
133621	DELTA SEC CO INC	Shut-In/TA	8,033	8,050	3,160	9,527	5.30
135648	DELTA SEC CO INC	Shut-In/TA	7,610	7,614	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,356	8,366	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,092	8,102	3,160	9,527	5.24
135648	DELTA SEC CO INC	Shut-In/TA	8,029	8,036	3,160	9,527	5.24
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	10,318	10,338	3,048	8,673	6.92
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	11,472	11,486	3,048	8,673	6.92
135728	PAR PZ RAB SU;LL&E	Shut-In/TA	10,994	11,004	3,048	8,673	6.92
135895	DELTA SEC CO INC A	Shut-In/TA	7,460	7,465	3,199	9,781	5.32
135895	DELTA SEC CO INC A	Shut-In/TA	7,420	7,465	3,199	9,781	5.32
136793	DELTA SEC CO INC A	Shut-In/TA	6,909	6,936	3,199	9,781	5.31

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
136793	DELTA SEC CO INC A	Shut-In/TA	6,888	6,936	3,199	9,781	5.31
136794	DELTA SEC CO INC	Shut-In/TA	7,570	7,672	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	7,692	7,872	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	6,929	6,935	3,199	9,781	5.41
136794	DELTA SEC CO INC	Shut-In/TA	6,880	6,915	3,199	9,781	5.41
136931	LL&E PARADIS	Shut-In/TA	10,202	10,212	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,244	10,252	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,840	10,864	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,986	11,010	3,145	8,940	6.50
136931	LL&E PARADIS	Shut-In/TA	10,700	10,718	3,145	8,940	6.50
138411	DELTA SEC CO INC A	Shut-In/TA	6,963	6,979	3,199	9,781	5.45
138891	DELTA SEC CO INC	Shut-In/TA	5,234	5,252	3,132	9,506	5.89
140064	DELTA SEC CO INC	Shut-In/TA	7,882	7,904	3,023	8,951	6.06
140064	DELTA SEC CO INC	Shut-In/TA	6,420	6,424	3,023	8,951	6.06
142732	BIG N 1 RB SUA;C E GHEENS	Shut-In/TA	6,920	6,946	2,938	9,703	3.72
142732	BIG N 1 RB SUA;C E GHEENS	Shut-In/TA	7,293	7,300	2,938	9,703	3.72
153593	DELTA SEC CO INC	Shut-In/TA	5,253	5,284	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,474	5,536	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	6,230	6,264	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,650	5,686	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	6,950	6,955	3,023	8,951	6.03
153593	DELTA SEC CO INC	Shut-In/TA	5,942	5,947	3,023	8,951	6.03

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
153594	DELTA SEC CO INC	Shut-In/TA	5,436	5,478	3,132	9,506	5.82
153594	DELTA SEC CO INC	Shut-In/TA	5,638	5,703	3,132	9,506	5.82
153594	DELTA SEC CO INC	Shut-In/TA	5,559	5,568	3,132	9,506	5.82
154522	C E GHEENS	Shut-In/TA	7,876	7,888	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	7,958	7,986	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	7,986	8,030	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	8,030	8,053	2,939	9,622	3.87
154522	C E GHEENS	Shut-In/TA	8,053	8,061	2,939	9,622	3.87
155760	DELTA SEC CO INC	Shut-In/TA	5,514	5,518	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,686	5,692	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,674	5,678	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,668	5,671	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,910	5,916	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	5,908	5,918	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,254	6,274	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	7,252	7,266	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,727	6,736	2,982	9,365	6.06
155760	DELTA SEC CO INC	Shut-In/TA	6,891	6,895	2,982	9,365	6.06
155761	DELTA SEC CO INC	Shut-In/TA	5,433	5,436	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	5,412	5,424	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	7,466	7,533	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,250	6,265	3,108	9,220	5.97

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
155761	DELTA SEC CO INC	Shut-In/TA	6,872	6,868	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,945	6,955	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,185	6,189	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	5,894	5,900	3,108	9,220	5.97
155761	DELTA SEC CO INC	Shut-In/TA	6,230	6,250	3,108	9,220	5.97
155929	DELTA SEC CO INC	Shut-In/TA	5,448	5,466	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	5,691	5,701	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	5,960	5,976	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,315	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,289	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	7,270	7,363	3,132	9,506	5.95
155929	DELTA SEC CO INC	Shut-In/TA	6,729	6,735	3,132	9,506	5.95
155930	DELTA SEC CO INC	Shut-In/TA	5,326	5,334	2,982	9,365	6.01
155930	DELTA SEC CO INC	Shut-In/TA	6,424	6,434	2,982	9,365	6.01
162959	DELTA SEC CO INC	Shut-In/TA	6,117	6,123	2,982	9,365	6.12
162959	DELTA SEC CO INC	Shut-In/TA	5,300	6,305	2,982	9,365	6.12
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,250	5,258	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,286	5,294	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,306	5,316	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,508	5,520	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	5,766	5,784	3,222	9,882	3.29
192950	DELTA SECURITIES CO INC	Shut-In/TA	6,156	6,180	3,222	9,882	3.29

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
192950	DELTA SECURITIES CO INC	Shut-In/TA	6,236	6,244	3,222	9,882	3.29
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,228	5,538	3,222	9,882	3.18
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,460	5,538	3,222	9,882	3.18
192951	DELTA SECURITIES CO INC	Shut-In/TA	5,460	5,528	3,222	9,882	3.18
195841	C E GHEENS	Shut-In/TA	7,655	7,660	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,675	7,688	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,691	7,708	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,770	7,802	2,938	9,703	3.88
195841	C E GHEENS	Shut-In/TA	7,808	7,816	2,938	9,703	3.88
197118	C E GHEENS	Shut-In/TA	7,026	7,042	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,566	7,577	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,674	7,705	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,720	7,728	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,944	7,968	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	7,977	7,988	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,176	8,192	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,212	8,217	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,142	8,164	2,646	9,470	4.38
197118	C E GHEENS	Shut-In/TA	8,262	8,272	2,646	9,470	4.38
197782	SL 348	Shut-In/TA	4,882	4,886	2,962		3.70
197782	SL 348	Shut-In/TA	4,955	4,963	2,962		3.70
197782	SL 348	Shut-In/TA	6,746	6,752	2,962		3.70

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
197782	SL 348	Shut-In/TA	6,927	6,972	2,962		3.70
204744	C E GHEENS	Shut-In/TA	4,884	4,896	2,938	9,703	4.00
204744	C E GHEENS	Shut-In/TA	7,904	7,912	2,938	9,703	4.00
204744	C E GHEENS	Shut-In/TA	8,126	8,148	2,938	9,703	4.00
205599	C E GHEENS	Shut-In/TA	7,319	7,353	2,962		3.74
205599	C E GHEENS	Shut-In/TA	8,054	8,066	2,962		3.74
205599	C E GHEENS	Shut-In/TA	8,170	9,192	2,962		3.74
205599	C E GHEENS	Shut-In/TA	8,219	8,226	2,962		3.74
205599	C E GHEENS	Shut-In/TA	8,264	8,275	2,962		3.74
205599	C E GHEENS	Shut-In/TA	8,287	8,300	2,962		3.74
205601	C E GHEENS	Shut-In/TA	7,552	7,561	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,726	7,736	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,749	7,758	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,825	7,830	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	7,891	7,917	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	8,042	8,062	2,646	9,470	4.05
205601	C E GHEENS	Shut-In/TA	8,000	8,035	2,646	9,470	4.05
205767	C E GHEENS	Shut-In/TA	7,388	7,398	2,646	9,470	4.29
205767	C E GHEENS	Shut-In/TA	7,660	7,672	2,646	9,470	4.29
205767	C E GHEENS	Shut-In/TA	7,728	7,770	2,646	9,470	4.29
205815	BDA 5000 RA SU; ST CHARLES B	Shut-In/TA	5,015	5,021	3,328	9,891	3.08
206041	C E GHEENS	Shut-In/TA	7,333	7,339	2,938	9,703	3.75

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
206041	C E GHEENS	Shut-In/TA	7,096	7,110	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,555	7,557	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,618	7,622	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,624	7,641	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,718	7,732	2,938	9,703	3.75
206041	C E GHEENS	Shut-In/TA	7,736	7,744	2,938	9,703	3.75
207261	C E GHEENS	Shut-In/TA	6,136	6,142	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	6,152	6,157	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	7,672	7,682	2,938	9,703	3.68
207261	C E GHEENS	Shut-In/TA	7,703	7,720	2,938	9,703	3.68
207417	C E GHEENS	Shut-In/TA	7,275	7,277	2,962		3.89
207417	C E GHEENS	Shut-In/TA	7,283	7,292	2,962		3.89
207417	C E GHEENS	Shut-In/TA	7,311	7,319	2,962		3.89
207417	C E GHEENS	Shut-In/TA	7,432	7,438	2,962		3.89
207417	C E GHEENS	Shut-In/TA	7,448	7,454	2,962		3.89
207417	C E GHEENS	Shut-In/TA	7,480	7,486	2,962		3.89
208094	C E GHEENS	Shut-In/TA	7,262	7,270	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	7,880	7,952	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	8,121	8,130	2,938	9,703	3.92
208094	C E GHEENS	Shut-In/TA	7,993	8,004	2,938	9,703	3.92
208420	X RA SUA;SL 348	Shut-In/TA	5,116	5,131	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	5,128	5,130	3,359	9,951	3.30

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
208420	X RA SUA;SL 348	Shut-In/TA	5,585	5,695	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	7,160	7,166	3,359	9,951	3.30
208420	X RA SUA;SL 348	Shut-In/TA	7,210	7,217	3,359	9,951	3.30
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,872	9,884	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,116	10,145	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,248	10,330	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	10,288	10,330	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,874	9,876	3,153	9,029	5.98
209805	PAR PZ RAB SU;SR&P	Shut-In/TA	9,916	9,934	3,153	9,029	5.98
209806	LL&E PARADIS	Shut-In/TA	10,218	10,228	3,153	9,029	5.96
213809	PAR PZ RAB SU;LL&E	Shut-In/TA	9,886	10,213	3,097	8,938	6.29
213809	PAR PZ RAB SU;LL&E	Shut-In/TA	9,886	9,898	3,097	8,938	6.29
228140	DELTA SEC CO INC	Shut-In/TA	7,076	7,112	3,225	9,679	5.20
228140	DELTA SEC CO INC	Shut-In/TA	7,132	7,236	3,225	9,679	5.20
228140	DELTA SEC CO INC	Shut-In/TA	7,282	7,355	3,225	9,679	5.20
228544	DELTA SEC CO INC	Shut-In/TA	7,970	8,012	3,160	9,527	5.19
228544	DELTA SEC CO INC	Shut-In/TA	8,230	8,569	3,160	9,527	5.19
239908	C E GHEENS	Shut-In/TA	7,095	7,104	2,962		4.27
239908	C E GHEENS	Shut-In/TA	7,126	7,132	2,962		4.27
239908	C E GHEENS	Shut-In/TA	7,332	7,543	2,962		4.27
239908	C E GHEENS	Shut-In/TA	7,390	7,543	2,962		4.27
239908	C E GHEENS	Shut-In/TA	7,390	7,422	2,962		4.27

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
245470	DELTA SEC CO INC	Shut-In/TA	2,705	2,709	3,108	9,220	5.75
252282	DELTA SEC CO INC	Shut-In/TA	6,834	6,838	3,132	9,506	5.54
252333	DELTA SEC CO INC	Shut-In/TA	4,753	4,890	3,108	9220	5.95

1.11.10 Wells Drilled in the Area Without Perforations

Table 1-25 lists the wells within 5 mi of the area boundary that were drilled but that do not contain records of having been perforated. All wells are either shut-in, temporarily abandoned, plugged, or orphan wells.

Table 1-25 – Wells without perforation records within 5 mi of the area boundary.

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
79525	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,438	9,681	0.50
125786	ST CHARLES LD & TRUST CO C	Dry/Plugged	0	0	3,457	9,993	0.95
168952	L B SIMONEAUX ET AL	Dry/Plugged	0	0	3,456	9,688	1.02
186005	L B SIMONEAUX	Dry/Plugged	0	0	3,456	9,688	1.11
186913	L B SIMONEAUX	Dry/Plugged	0	0	3,456	9,688	1.11
151705	SIMONEAUX	Dry/Plugged	0	0	3,429	9,979	1.19
108246	MRS L B SIMONEAUX ET AL	Dry/Plugged	0	0	3,404	9,727	1.22
193508	W R WHITE ET AL	Dry/Plugged	0	0	3,437	9,384	1.80
88612	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,282	9,266	2.05
151856	MORNA E DUSENBURY ET AL	Dry/Plugged	0	0	3,437	9,384	2.08
81236	WATERFORD OIL CO	Dry/Plugged	0	0	3,433	9,941	2.34
56972	S J SIMONEAUX	Orphan Well	0	0	3,510	9,971	2.40
167807	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,282	9,266	2.43
33280	S J SIMONEAUX	Orphan Well	0	0	3,574	9,960	2.43
138798	W H TALBOT	Dry/Plugged	0	0	3,312	9,247	2.43
211003	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,375	9,261	2.47
87029	LYDIA B SIMONEAUX ET AL	Dry/Plugged	0	0	3,296	9,302	2.52
69940	SIMONEAUX	Orphan Well	0	0	3,479	9,968	2.54
116758	ST CHARLES LAND TRUST	Dry/Plugged	0	0	3,280	9,926	2.59
115365	ST CHARLES LD CO A RA B	Dry/Plugged	0	0	3,359	9,966	2.59
178079	SIMONEAUX	Dry/Plugged	0	0	3,280	9,926	2.73
31709	ST CHARLES LAND CO	Dry/Plugged	0	0	3,359	9,966	2.73

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
137534	WM H TALBOT ETAL	Dry/Plugged	0	0	3,364	9,343	2.80
68317	SIMONEAUX	Dry/Plugged	0	0	3,280	9,926	2.81
251479	SELLERS HEIRS	Dry/Plugged	0	0	3,489	9,997	2.87
53428	SIMONEAUX	Dry/Plugged	0	0	3,359	9,966	2.89
108450	WILLIAM H TALBOT ET AL	Dry/Plugged	0	0	3,312	9,247	2.90
191264	ST CHARLES LAND CO A R/AA	Dry/Plugged	0	0	3,479	9,968	2.93
251714	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,479	9,968	2.93
114248	ST CHARLES LD CO A RA A	Dry/Plugged	0	0	3,479	9,968	2.98
56468	L B SIMONEAUX	Dry/Plugged	0	0	3,285	9,163	2.98
143907	IRELAND FEE	Dry/Plugged	0	0	3,310	9,254	2.99
113185	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	2.99
53063	WILLIAM H TALBOT	Dry/Plugged	0	0	3,276	9,135	3.03
108102	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	3.10
140976	M D SUMNERS ETAL	Dry/Plugged	0	0	3,580	9,822	3.11
164763	RATHBORNE LAND COMPANY INC	Dry/Plugged	0	0	3,272	9,203	3.11
150230	MITCHELL-NEELY FEE	Dry/Plugged	0	0	3,309	9,226	3.11
180305	L B SIMONEAUX	Dry/Plugged	0	0	3,325	9,458	3.13
107800	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,116	9,831	3.14
173741	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,422	9,549	3.20
121958	HUMBLE OIL & REFINING CO	Dry/Plugged	0	0	2,960	9,744	3.22
57829	JOSEPH RATHBORNE LAND & LBR CO	Dry/Plugged	0	0	3,251	9,093	3.24
95696	T B SELLERS	Dry/Plugged	0	0	3,489	9,997	3.27
173742	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,422	9,549	3.31
120976	HUMBLE O&R CO	Dry/Plugged	0	0	2,960	9,744	3.32
73869	RATHBORNE LAND & LUMBER	Dry/Plugged	0	0	3,248	9,109	3.32
21973	ST CHARLES LAND CO	Dry/Plugged	0	0	3,328	9,891	3.33
90455	SIMONEAUX	Dry/Plugged	0	0	3,222	9,882	3.35
142437	HANS C BLOCK FEE	Dry/Plugged	0	0	3,282	9,178	3.35
44831	SIMONEAUX	Dry/Plugged	0	0	3,328	9,891	3.39
20423	ST CHARLES LAND CO	Dry/Plugged	0	0	3,328	9,891	3.40
124302	HUMBLE OIL & REFG CO	Dry/Plugged	0	0	2,960	9,744	3.40
202150	M D SUMNERS	Dry/Plugged	0	0	3,497	9,719	3.40
60445	DELTA SEC CO INC	Dry/Plugged	0	0	3,353	10,013	3.40
116872	T B SELLERS	Dry/Plugged	0	0	3,547	10,057	3.41
116759	ST CHARLES LAND TRUST B	Dry/Plugged	0	0	2,812	9,617	3.48
50557	ST CHARLES LAND CO B	Dry/Plugged	0	0	2,939	9,622	3.49
73363	RATHBORNE LAND & LUMBER	Dry/Plugged	0	0	3,251	9,093	3.55
118175	DELTA SECURITIES	Dry/Plugged	0	0	2,845	9,665	3.57
172018	PAR 8 RA SU;IRELAND	Dry/Plugged	0	0	3,451	9,518	3.58

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
180436	SIMONEAUX	Dry/Plugged	0	0	2,812	9,617	3.60
152640	MITCHELL & NEELY	Dry/Plugged	0	0	3,276	9,048	3.61
139476	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,217	9,091	3.62
117375	C E GHEENS	Dry/Plugged	0	0	2,938	9,703	3.62
49051	IRELAND FEE	Dry/Plugged	0	0	3,497	9,719	3.65
48783	JOESPH RATHBORNE LD LBR CO	Dry/Plugged	0	0	3,242	9,181	3.65
115907	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.68
78858	JOSEPH RATHBORNE LAND CO INC	Orphan Well	0	0	3,223	9,018	3.68
154381	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.71
105439	DELTA SEC CO INC	Dry/Plugged	0	0	2,845	9,665	3.73
195630	C E GHEENS	Shut-In/TA	0	0	2,962		3.74
217805	PAR 9500 RD SU;WIDENER	Dry/Plugged	0	0	3,304	9,259	3.75
62946	DELTA SEC B	Dry/Plugged	0	0	2,813	9,688	3.77
109671	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.81
84549	C E GHEENS	Dry/Plugged	0	0	2,938	9,703	3.86
162352	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,214	9,040	3.89
199967	VUA;JOS RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,214	9,040	3.90
134633	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,329	9,442	3.90
207262	C E GHEENS	Dry/Plugged	0	0	3,419		3.93
174198	MITCHELL & NEELEY	Dry/Plugged	0	0	3,242	8,960	3.94
152158	SL 6184	Dry/Plugged	0	0	3,273	9,261	3.95
107747	WATERFORD	Dry/Plugged	0	0	2,813	9,688	3.95
38575	C E GHEENS	Dry/Plugged	0	0	2,939	9,622	3.95
157205	RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,210	9,039	3.97
251822	EMC FEE A	Dry/Plugged	0	0	2,813	9,688	3.98
228861	EXXONMOBIL FEE	Dry/Plugged	0	0	3,226	9,856	3.99
27512	C E GHEENS	Dry/Plugged	0	0	3,100		4.01
202777	ST CHARLES PH SCHL BD	Dry/Plugged	0	0	3,316	9,379	4.03
40494	G E GHEENS	Dry/Plugged	0	0	2,707	9,217	4.06
34610	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,327	9,953	4.09
88410	WATERFORD OIL CO B	Dry/Plugged	0	0	3,448	10,034	4.11
228795	EXXONMOBIL FEE	Dry/Plugged	0	0	3,327	9,953	4.14
92455	W H TALBOT ETAL	Dry/Plugged	0	0	3,223	9,018	4.15
165395	IRELAND FEE	Dry/Plugged	0	0	3,165	9,054	4.17
186151	JOS RATHBORNE LAND CO INC A	Dry/Plugged	0	0	3,214	9,040	4.18
140130	IRELAND FEE	Dry/Plugged	0	0	3,462	9,519	4.18

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
108028	RATHBORNE LD & LBR CO INC	Dry/Plugged	0	0	3,214	9,040	4.20
207741	C E GHEENS	Dry/Plugged	0	0	3,100		4.24
115161	C E GHEENS	Dry/Plugged	0	0	2,638		4.25
40970	C E GHEENS	Dry/Plugged	0	0	3,100		4.26
96089	J RATHBORNE L & L CO INC	Dry/Plugged	0	0	3,232	9,155	4.28
251447	DEVON MARR	Dry/Plugged	0	0			4.30
143281	C E GHEENS	Dry/Plugged	0	0	2,646	9,470	4.31
116132	C E GHEENS	Dry/Plugged	0	0	2,836		4.35
59256	WATERFORD OIL CO B	Dry/Plugged	0	0	3,388	10,108	4.36
121984	C E GHEENS	Dry/Plugged	0	0			4.37
35837	C E GHEENS	Dry/Plugged	0	0	2,638		4.44
83940	JOS RATHBORNE LAND & LUMBER CO	Dry/Plugged	0	0	3,189	8,949	4.46
154382	C E GHEENS	Dry/Plugged	0	0	2,638		4.50
145893	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,264	9,191	4.51
143407	C E GHEENS	Dry/Plugged	0	0	2,638		4.52
85670	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,162	9,781	4.52
143908	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.56
38223	C E GHEENS	Dry/Plugged	0	0	2,836		4.57
147388	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.59
207279	MITCHELL & NEELY	Dry/Plugged	0	0	3,169	8,805	4.63
84631	WATERFORD	Dry/Plugged	0	0	3,255	9,794	4.70
69431	T C DUFRENE	Dry/Plugged	0	0	3,044	9,027	4.71
53320	DELTA SEC CO INC	Dry/Plugged	0	0	3,255	9,794	4.74
142325	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.75
99536	JOS RATHBORNE LD CO INC	Dry/Plugged	0	0	3,186	8,945	4.76
30704	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,541	10,087	4.79
213352	EXXON FEE	Dry/Plugged	0	0	3,423	10,011	4.82
32297	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,423	10,011	4.83
70738	DELTA SEC CO INC A	Dry/Plugged	0	0	3,312	9,867	4.83
83422	WATERFORD OIL CO	Dry/Plugged	0	0	3,183	9,699	4.86
199376	RATHBORNE LAND CO	Dry/Plugged	0	0	3,215	9,093	4.86
143461	IRELAND FEE	Dry/Plugged	0	0	3,458	9,526	4.86
31755	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,423	10,011	4.87
51640	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	4.88
235980	CIB O RA SUA;EXXONMOBIL FEE	Dry/Plugged	0	0	3,423	10,011	4.90
72631	WATERFORD OIL CO	Dry/Plugged	0	0	3,399	10,087	4.91
28543	PETER REISCH	Dry/Plugged	0	0	2,926	8,916	4.92
166914	EXXON FEE	Dry/Plugged	0	0	2,698	9,541	4.92

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
41463	C E CHEENS	Dry/Plugged	0	0	2,596	9,413	4.94
72001	DELTA SECURITIES CO INC A	Dry/Plugged	0	0	3,312	9,867	4.97
28616	C E GHEENS	Dry/Plugged	0	0	2,725		4.97
117891	RATHBORNE LND & LBR CO	Dry/Plugged	0	0	3,164	8,888	4.99
152117	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,277	9,243	5.00
226082	IRELAND FEE	Dry/Plugged	0	0			5.01
55613	DELTA S C CO INC	Dry/Plugged	0	0	3,225	9,679	5.08
47175	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.09
97884	JOS RATHBORNE LAND CO INC	Dry/Plugged	0	0	3,167	8,869	5.09
50669	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.11
48648	DELTA SEC CO INC	Dry/Plugged	0	0	3,160	9,527	5.12
50416	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,754	9,638	5.17
123250	10000 RB SUB;CLAUDE AUTIN	Dry/Plugged	0	0	3,400	9,393	5.18
54825	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.19
137241	IRELAND FEE	Dry/Plugged	0	0	2,989	8,824	5.19
43270	DELTA SEC CO INC	Dry/Plugged	0	0	3,199	9,781	5.19
44414	DELTA SEC CO INC	Dry/Plugged	0	0	3,312	9,867	5.19
142842	IRELAND FEE	Dry/Plugged	0	0	3,538		5.20
47827	DELTA SEC CO INC	Dry/Plugged	0	0	3,225	9,679	5.23
160295	SUNSET REALTY & PLANTING CO	Dry/Plugged	0	0	3,097	9,024	5.23
61848	W H TALBOT ETAL	Dry/Plugged	0	0	3,154	8,830	5.24
57707	WATERFORD OIL COMPANY	Dry/Plugged	0	0	2,951	9,710	5.24
64758	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,238	9,612	5.25
30232	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,225	9,679	5.28
146352	THOMAS GREEN	Dry/Plugged	0	0	3,400	9,393	5.29
27720	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.33
146879	S/L 6391	Dry/Plugged	0	0			5.33
51349	DELTA SEC CO INC	Dry/Plugged	0	0	3,160	9,527	5.36
124076	DELTA SECURITIES	Dry/Plugged	0	0	3,199	9,781	5.36
228543	DELTA SEC CO INC	Dry/Plugged	0	0	3,199	9,781	5.39
85381	JOESPH RATHBORNE LD LBR CO INC	Dry/Plugged	0	0	3,210	9,298	5.48
33722	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.50
72608	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,132	9,506	5.69
53706	DELTA SEC CO INC	Dry/Plugged	0	0	3,132	9,506	5.74
210859	THE LEON GODCHAUX CO LTD	Dry/Plugged	0	0	3,410	9,403	5.76
153595	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,108	9,220	5.78
73215	DELTA SEC CO INC /A	Dry/Plugged	0	0	3,093	9,477	5.82

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
28441	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	5.89
27882	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,012	9,701	5.90
23759	MATHEWS OLIVIERS	Dry/Plugged	0	0	3,045	8,734	5.90
28032	ELLINGTON	Dry/Plugged	0	0	3,082	8,570	5.92
46132	DELTA SEC CO INC	Dry/Plugged	0	0	3,012	9,701	5.95
122383	J B PEYREGNE	Dry/Plugged	0	0	3,355	9,287	5.95
27584	MRS PAUL PEYREGNE	Dry/Plugged	0	0	3,355	9,287	6.03
240448	BOWIE LUMBER CO	Dry/Plugged	0	0	3,410	9,403	6.11
71411	DELTA SECURITIES CO INC A	Dry/Plugged	0	0	3,012	9,701	6.11
25010	A P PEYREGNE	Dry/Plugged	0	0	3,438		6.14
48479	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	6.14
140649	A T PEYREGNE ET AL	Dry/Plugged	0	0	3,438		6.16
138588	GORDON REESE	Dry/Plugged	0	0	3,109	8,669	6.18
41571	DELTA SEC CO INC	Dry/Plugged	0	0	2,982	9,365	6.19
83040	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,108	9,220	6.19
87425	J B LEVERT LAND COMPANY	Dry/Plugged	0	0		8,665	6.25
30110	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,982	9,365	6.31
98328	WATERFORD OIL CO	Dry/Plugged	0	0	2,899	9,687	6.37
30546	DELTA SECURITIES CO INC	Dry/Plugged	0	0	2,982	9,365	6.40
51054	DELTA SEC CO INC	Dry/Plugged	0	0	3,023	8,951	6.42
48770	DELTA SEC CO INC	Dry/Plugged	0	0	2,889	9,403	6.46
29339	DELTA SECURITIES CO INC	Dry/Plugged	0	0	3,023	8,951	6.47
76153	WATERFORD OIL COMPANY	Dry/Plugged	0	0	3,023	8,951	6.48
141244	J B LEVERT LAND CO INC	Dry/Plugged	0	0		8,665	6.50
53061	DELTA SEC CO INC	Dry/Plugged	0	0	2,889	9,403	6.53
84624	WATERFORD OIL CO	Dry/Plugged	0	0	3,094	9,861	6.53
169297	EXXON FEE	Dry/Plugged	0	0	3,027	8,850	6.58
78280	WATERFORD OIL COMPANY	Dry/Plugged	0	0	2,899	9,687	6.66
80424	WATERFORD OIL CO	Dry/Plugged	0	0	2,889	9,403	6.70
23604	C L THOMPSON FEE	Dry/Plugged	0	0		8,351	7.05
78834	LEVERT LAND CO	Dry/Plugged	0	0		8,548	7.40
88568	PENICK & SCHORNSTN	Dry/Plugged	0	0		8,724	7.41
196676	SL 11680	Dry/Plugged	0	0	3,548	10,019	7.43
62991	STATE LEASE 2827	Dry/Plugged	0	0	3,518	9,856	7.83
56482	J B LEVERT	Dry/Plugged	0	0		8,460	7.85
129528	EDWARD A DUFRESNE SR	Dry/Plugged	0	0		8,240	7.86
230941	LEVERT	Dry/Plugged	0	0		8,460	8.05
195350	SL 11135	Dry/Plugged	0	0		9,658	8.11
58976	STATE LEASE 2828	Dry/Plugged	0	0	3,518	9,856	8.29
62800	STATE LEASE 2828	Dry/Plugged	0	0	3,518	9,856	8.29

Serial Number	Well Name	Status	Upper Perfs	Lower Perfs	Top of Injection	Base of Injection	Distance (Mi)
73972	WATERFORD	Dry/Plugged	0	0		8,805	8.33
70244	E P BRANDY /C/	Dry/Plugged	0	0		8,898	8.53
84185	JOHN F BRICKER ETAL	Dry/Plugged	0	0		9,359	8.61
211210	MARSH INVESTMENT CORP	Dry/Plugged	0	0		8,729	8.75
244013	12200 RA SUA;M L MANN ETAL	Orphan Well	0	0		8,729	8.75

1.11.11 Wells Located Within the AOR

Wells within the modeled CO_2 plume extent and critical pressure front were identified and are listed in Table 1-26. A review of the well data has resulted in identifying five active wells located within the plume and critical pressure front, four of which fall below the injection zone. Since these wells are located below the injection zone, the Libra project will not affect any oil and gas production for these wells.

A closer look at the well files for LYDIA B SIMONEAUX ET AL SWD (SN 68811) indicated that the well is active and was permitted in December 2021 to inject between 3,337 ft and 6,700 ft. Currently, the well is perforated from 6,590 ft to 6,610 ft. As referenced in greater detail in *Section 2 – Plume Model*, SN 68811 had no observable impact on the plume or critical pressure front when compared to model runs without water injection. Moreover, the Libra project will not affect ongoing operations for SN 68811.

The remaining 16 wells identified in the search are either dry holes, plugged and abandoned, shut in, or have an expired permit. None of these wells will be affected by the Libra project.

Table 1-26 – Wells within the AOR

Serial Number	Well Name	Well Number	Status	Upper Perfs	Lower Perfs
79525	LYDIA B SIMONEAUX ET AL	16	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
125786	ST CHARLES LD & TRUST CO C	1	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
75831	LYDIA B SIMONEAUX ET AL	15	PLUGGED AND ABANDONED GAS	10,945	10,954
237172	VUC;SIMONEAUX FAMILY LAND LLC	3	PLUGGED AND ABANDONED GAS	11,850	11,910
236901	VUB;SIMONEAUX FAMILY LAND LLC	1	PLUGGED AND ABANDONED GAS	11,066	11,112

Serial Number	Well Name	Well Number	Status	Upper Perfs	Lower Perfs
237039	VUB;SIMONEAUX FAMILY LAND LLC	2	PLUGGED AND ABANDONED GAS	11,404	11,414
166990	S J SIMONEAUX	1	PLUGGED AND ABANDONED GAS	10,871	10,875
151705	SIMONEAUX	1	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
168952	L B SIMONEAUX ET AL	1	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
186913	L B SIMONEAUX	2	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
186005	L B SIMONEAUX	1	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
108246	MRS L B SIMONEAUX ET AL	1	DRY AND PLUGGED PRODUCT NOT SPECIFIED	NA	NA
55235	LYDIA B SIMONEAUX ET AL	8	PLUGGED AND ABANDONED PRODUCT NOT SPECIFIED	11,012	11,032
51104	LYDIA B SIMONEAUX ET AL	7	SHUT-IN PRODUCTIVE - FUTURE UTILITY OIL	10,911	10,924
210373	LYDIA B SIMONEAUX ET AL	25	PERMIT EXPIRED	NA	NA
217145	LYDIA B SIMONEAUX ET AL	25	ACTIVE - PRODUCING OIL	10,265	10,267
68811	LYDIA B SIMONEAUX ET AL SWD	11	ACTIVE - INJECTION PRODUCED SALT WATER	10,953	10,991
250809	SIMONEAUX FAMILY LAND LLC A	1	ACTIVE - PRODUCING GAS	13,774	13,940
250810	SIMONEAUX FAMILY LAND LLC	2	ACTIVE - PRODUCING GAS	12,403	12,422
238687	VUD;SIMONEAUX FAMILY LAND LLC	5	PLUGGED AND ABANDONED NO PRODUCT SPECIFIED	11,832	11,840
250321	SIMONEAUX FAMILY LAND LLC	1	ACTIVE - PRODUCING GAS	12,500	12,544

1.12 Seismic History

Ensuring that injection activities will not induce a seismic response is a crucial evaluation in the design and development of any proposed injection-well project. The location of the Libra project AOR in St. Charles Parish is about 6 mi northwest of Lake Salvador and 17 mi southwest of New

Orleans. This region is part of the Cenozoic Eastern Province, a region in the northern Gulf of Mexico Basin that contains many piercement and deep-seated salt domes as well as surface and subsurface faults (Gagliano et al., 2003). The following evaluation of seismicity in the project area consisted of this four-step screening approach:

1. Identification of historical seismic events within proximity to the project
2. Faulting and determination of operational influences of nearby faults
3. Evaluation of fault slip potential
4. Seismic hazard review

1.12.1 Identification of Historical Seismic Events

Although there are no seismically active zones in southeast Louisiana, there have been a few historical earthquakes in the region. Stevenson and McCulloh (2001) identified more than 40 low-magnitude earthquakes in the state, all less than 4.4 magnitude; the study found that the most likely area where additional earthquakes could affect Louisiana is the seismic zone of New Madrid (western Tennessee), which produced the strongest felt earthquake in northern Louisiana in 1812. The Libra project seismic review region (SRR) used a 9.6 kilometer (km) (6 mi) radius to conduct the historical data investigation, (center at WGS84: 29.8124153, -90.3667171), covering the AOR and the three proposed injector wells.

The investigation found that zero events greater than a 2.0 magnitude were recorded within the SRR, according to the USGS[2] Earthquake Archive Search (Figure 1-64), and Texas Seismological Network Earthquake Catalog (TexNet) (Figure 1-65), from inception to April 2024. The SRR is monitored by one TexNet seismic monitoring station located 28 km northwest of the proposed project injection sites. As seismic records do not exist in the SRR, another USGS catalog research was conducted using a 60 km radius (Figure 1-66) to establish the closest known earthquake to the project area. This evaluation demonstrated that only one earthquake has occurred within the expanded radius, about 59.3 km northwest from the center of the SRR, in Livingston Parish, Louisiana. This event (ID No. usp000e6fr) occurred at a depth of 5 km with a recorded magnitude of 3.0.

[2] The USGS Earthquake Catalog is a database of seismographic recordings from a global network of seismological stations around the world.

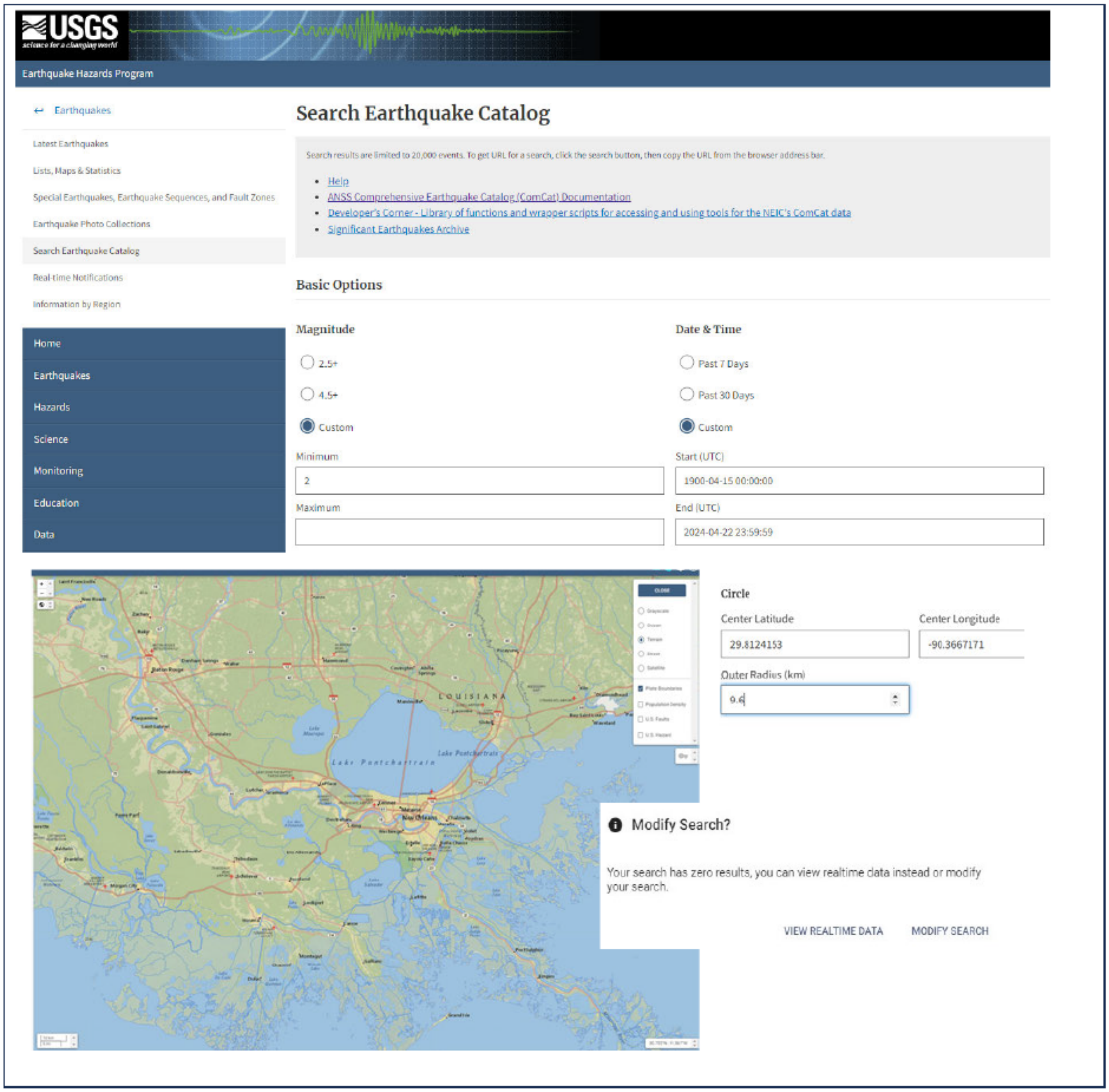

Figure 1-64 – USGS catalog showing search parameters and historical earthquakes (zero) within the seismic review region.

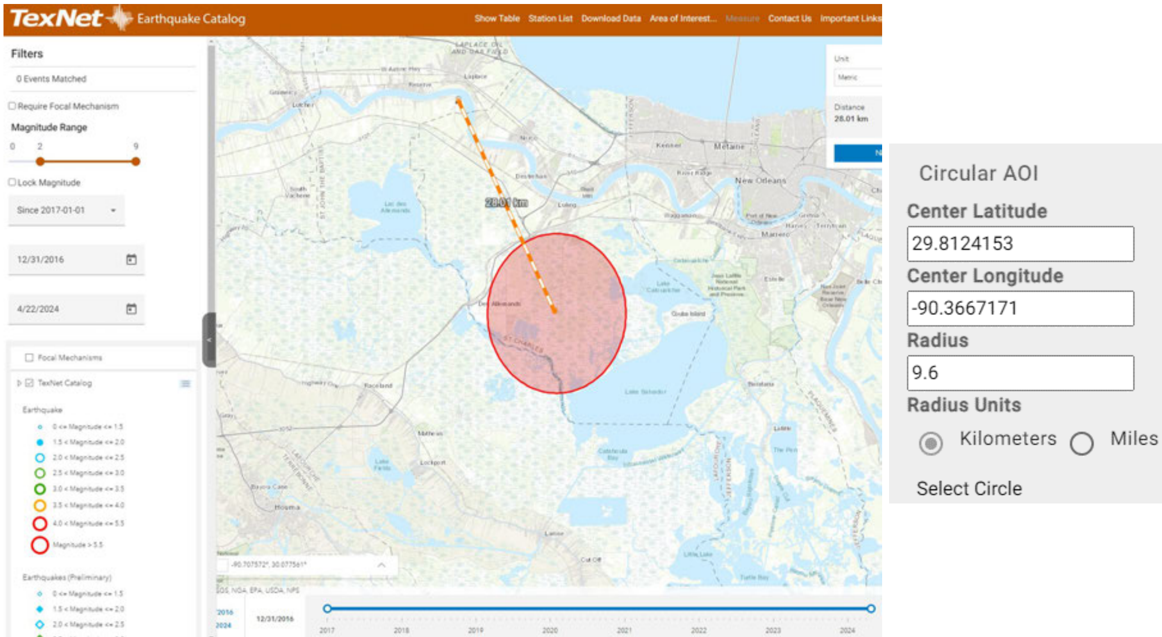

Figure 1-65 – TexNet catalog showing historical earthquakes (zero) and the closest seismic monitoring station, 28 km northwest of the seismic review region.

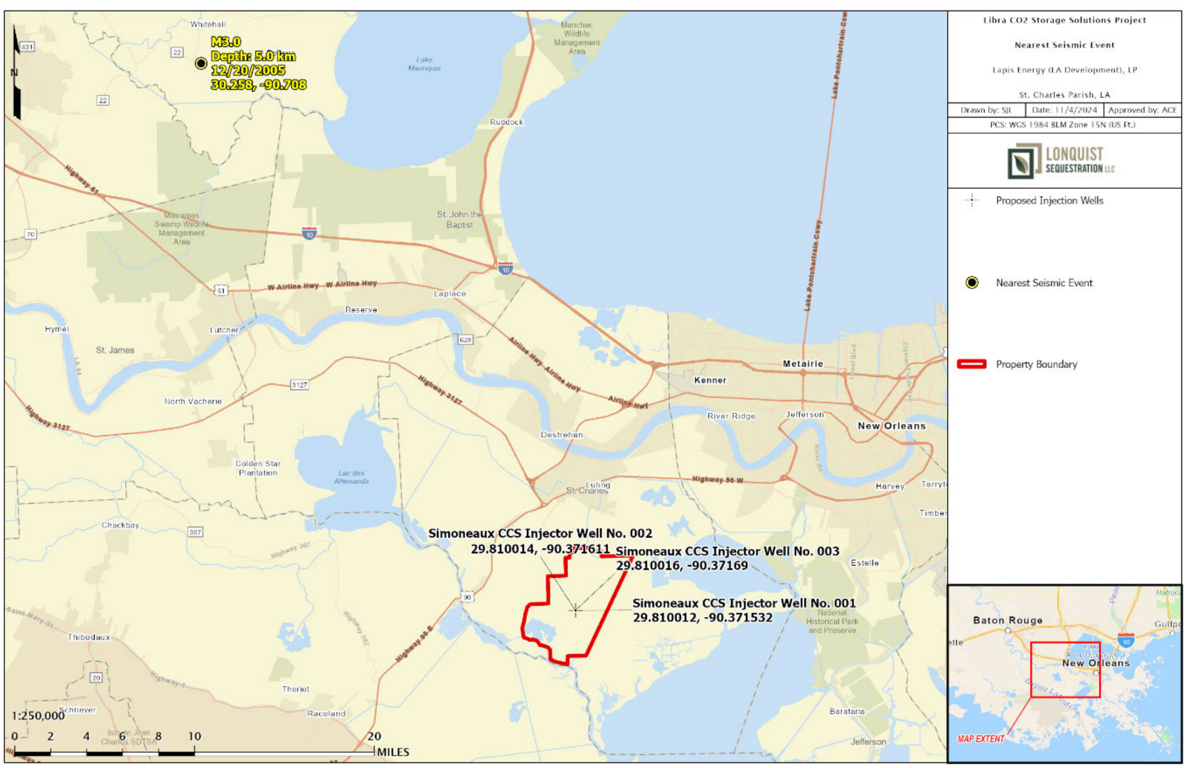

Figure 1-66 – Nearest historical earthquake recorded by the USGS catalog (ID No. usp000e6fr) in relation to the Libra project site.

1.12.2 Faults and Influence

The fault system in southeast Louisiana is primarily considered “Gulf-margin normal faults (Class B).” This classification was given by the USGS in the Data for Quaternary Faults Report, based on analyses of faults and related folds throughout the United States. Regionally, faulting is predominately observed in poorly lithified sediments along a northeast-southwest trending strike; these faults are ductile and do not have the elastic strength to transmit the tectonic stress necessary for the creation of large seismic ruptures (Crone and Wheeler, 2000). A large number of the growth faults, which are mostly found in the southern part of the state (i.e., the Baton Rouge fault system), exhibit movement not in tandem with discernible earthquakes but rather as a slow kind of fault creep (Stevenson and McCulloh, 2001). The displacement has been linked to some specific listric faults in the intermediate system, between extension and compression (Figure 1-67). The majority of these faults are observed at 20,000–30,000 ft, which aligns with the Oligocene-Miocene detachment surface (Gagliano et al., 2003).

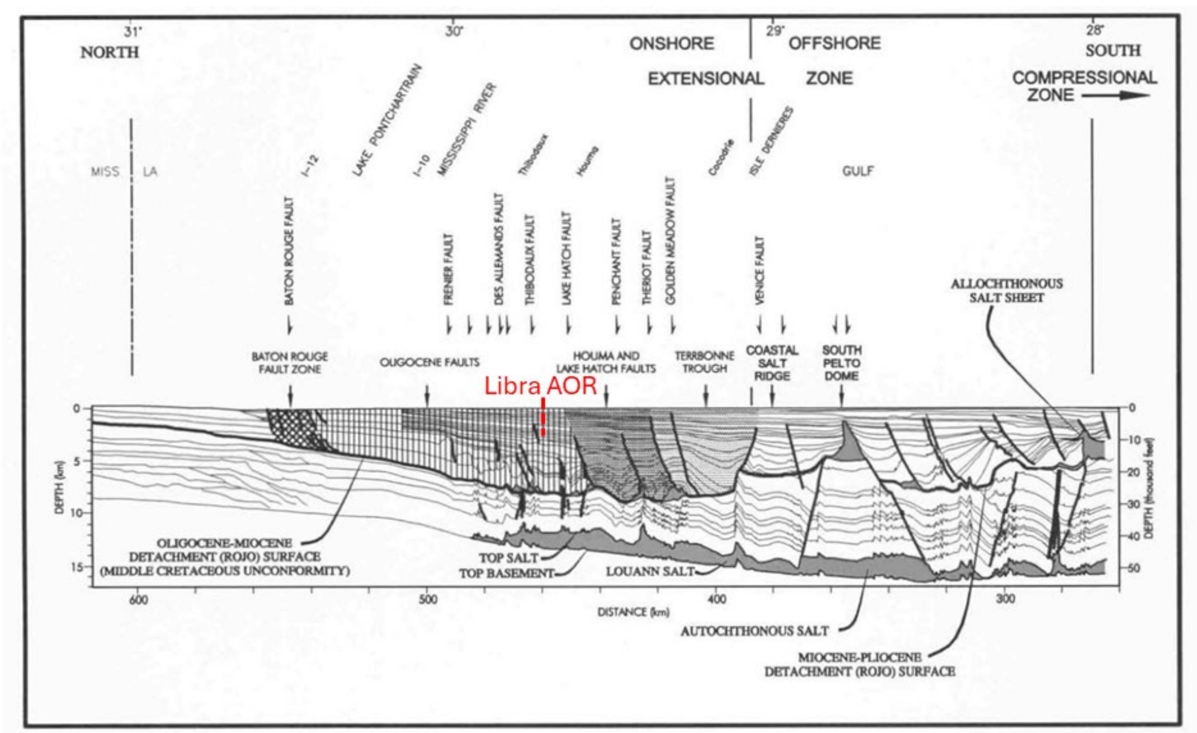

Figure 1-67 – Location of the Libra project AOR along a regional, structural north-south cross section schematic (modified from Gagliano et al., 2003).

The Libra project AOR is located in the onshore extensional zone, between the Lake Salvador faults (approximately 5.6 mi south) and Thibodaux faults (approximately 7.5 mi north), as shown in Figure 1-68. Three salt domes proximal to the AOR include the Bayou Couba dome (southeast, salt elevation 6,200 ft), Bayou Des Allemands dome (south, salt elevation 7, 650 ft), and Paradis dome (west, salt elevation 13,300 ft). The listric, normal, and antithetic faults associated with the salt domes were analyzed and do not have a negative impact on the AOR. The southeast boundary of the model is formed by one of the most northern faults (FS1_3GM) associated with the Bayou Couba salt dome. The fault is oriented southeast-northwest and considered to be the shallowest fault in the AOR. According to seismic data, there are more than 1,000 ft of sand and shale between this fault (trace to 2,050 ft) and the USDW (950 ft), which will preserve the integrity of the USDW. Despite the fact that the seismic data is too noisy to interpret shallower faults, it is apparent that no surface expressions exist until the Lake Salvador fault. All faults in the northern part of the project acreage terminate deep—at a depth of approximately 8,000–9,000 ft. Differential movement between the low-density salt and down-building of overlying and adjacent sedimentary deposits appears to have a wedging (space-creating) effect on the faults (Gagliano at al., 2003). All faults within the licensed 3D seismic data area (39 sq mi) have been identified, mapped, and extensively studied utilizing Petrel, presented in *Section 1.5* and *Section 1.6*. Additionally, as EPA regulations require, a complete understanding of the extent and location of the resultant injection plume is presented in *Section 2 – Plume Model*. Overall, the AOR appears stable and has little chance of causing earthquakes.

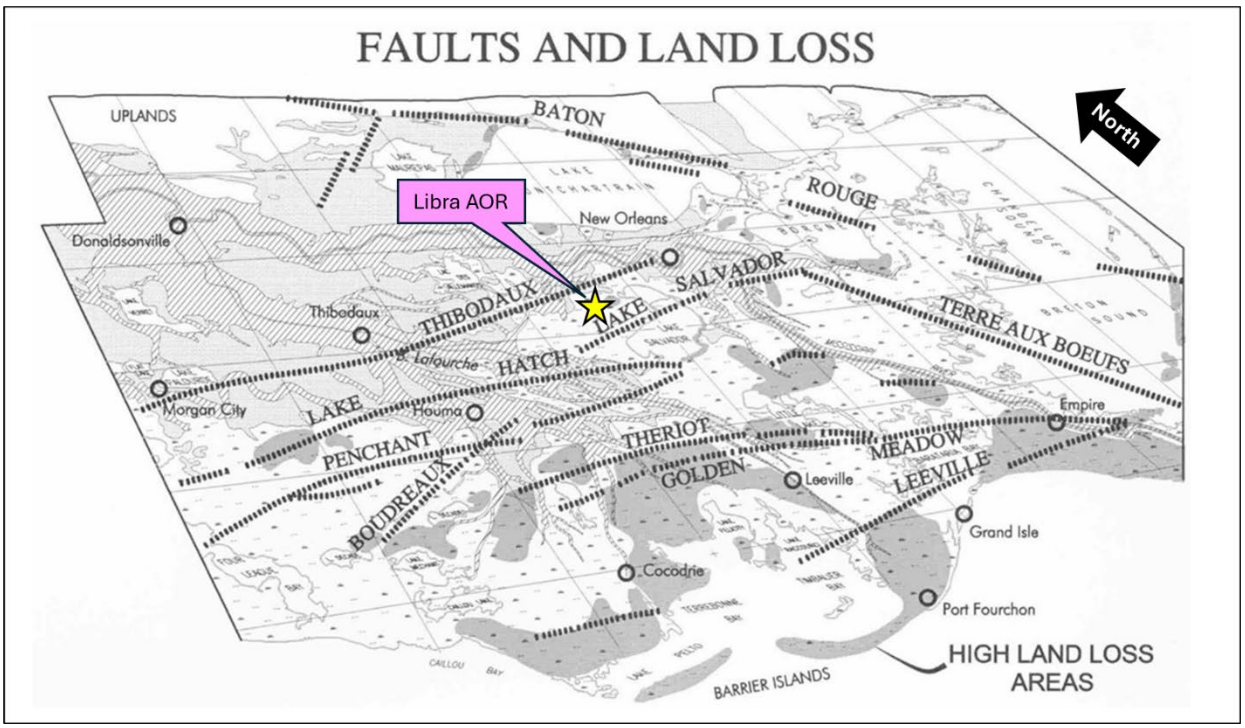

Figure 1-68 – Perspective map showing major fault systems in southeast Louisiana (modified from Gagliano et al., 2003).

1.12.3 Fault Slip Potential Model

Fault stability is critical in any sequestration project as pressure variation runs the risk of compromising the upper confining seal (hydraulically fractured) or lubricating the fault plane—causing reactivation (Meckel and Trevino, 2014). Regionally, no zones in Louisiana have been identified by the USGS National Seismic Hazard Maps to have induced seismicity (Petersen et al., 2023). However, for thoroughness, an FSP analysis was performed in the Libra project area, as the induced seismic risk was still somewhat uncertain. The detection of faults adjacent to the modeled CO_2 plume and pressure front extents warranted further evaluation. The FSP model calculates the cumulative likelihood of a known fault exceeding Mohr-Coulomb slip criteria due to fluid injection. The procedures used, findings, and data (assumptions or uncertainties) are discussed in *Appendix K*, based on the injection strategy and 3D Intersect™ flow simulation. Overall, the findings demonstrated that the faults are stable and that the expected maximum pore pressure (MPP) generated by the plume model (Intersect) never exceeded the pore pressure to failure (PPF) and would not reactivate any of the faults.

1.12.4 Seismic Hazard

To assess potential seismic hazards, the EPA proposes the use of the USGS National Seismic Hazard Model (NSHM) Project and maps generated from it as a seismic hazard assessment tool. This model was released in 2023, replacing the 2018 NSHM. The model integrates fault models, fault ruptures, seismic catalogs, magnitude scaling equations, ground motion models, soil amplification factors, multi-fault earthquake rupture forecast models, population density, probabilistic techniques, seismic hazard calculation, and Modified Mercalli Intensity (MMI[3]). Each of the 2023 MMI hazard maps reflects a different probability of exceedance (PE) during a given period of time. Observed first was the most likely scenario (Figure 1-69) that forecasts an earthquake of intensity III[4] in the northern Gulf of Mexico basin where the Libra project is located, with a 50% probability of exceedance in 50 years (firm rock). However, in a rare scenario it is possible the area could see an intensity V[5], as shown in Figure 1-70.

A different MMI hazard map, Figure 1-71, considers population exposure when estimating the likelihood that an earthquake of intensity VI[6], or a higher damaging earthquake[7], will occur within the next 100 years. The proposed project site falls in an area of low risk, ranging from 5% to 25%

[3] The Modified Mercalli Intensity (MMI) scale ranges from I to XII. The following summaries were taken from the USGS Earthquake Hazards Program, which were first condensed by Wood and Neumann in 1931.
[4] Intensity III: "Weak; Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a tuck. Duration estimated."
[5] Intensity V: "Moderate; Felt by nearly everyone, many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop."
[6] Intensity VI: "strong; Felt by all, and many are frightened. Some heavy furniture is moved; a few instances of fallen plaster occur. Damage is slight."
[7] Higher damaging earthquake meaning a level VI or higher earthquake causing slightly to high structural failure.

likelihood of occurrence. An intensity IX[8] earthquake is extremely unlikely to occur near the project site, per the 2023 NSHM. Finally, the location of the proposed project site falls within the lowest risk rating of fewer than 2 damaging earthquake occurrences per 10,000 year time period, as illustrated in Figure 1-72.

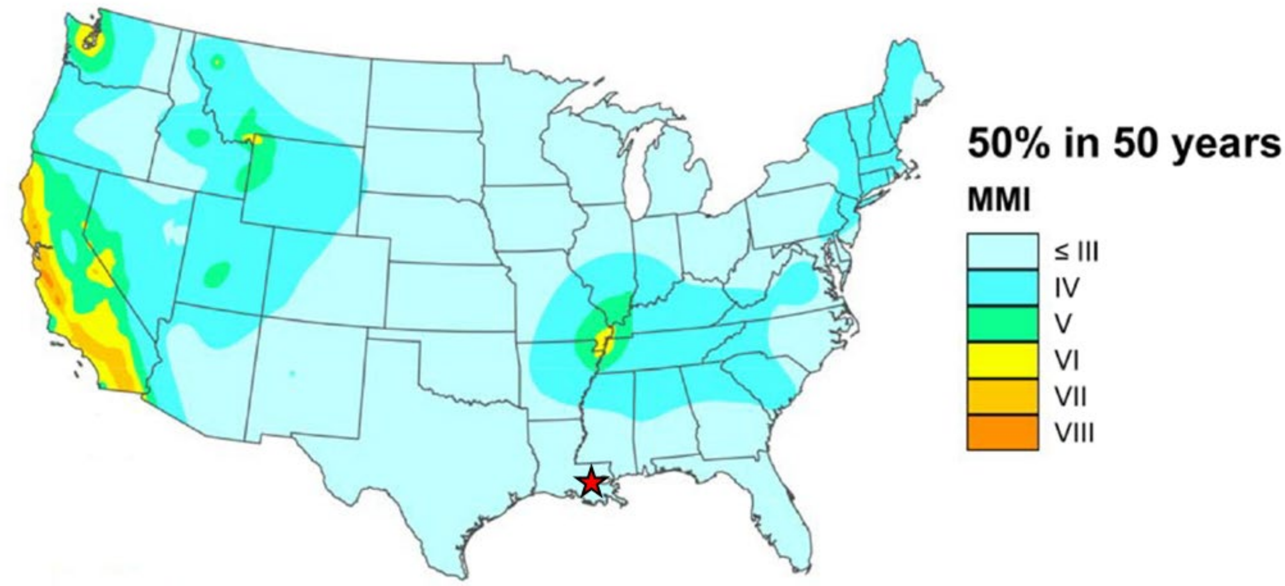

Figure 1-69 – Total mean seismic hazard map for 50% probability of occurrence in 50 years; the location of the Libra project is indicated by the red star in an area of "<III" MMI events (modified from Petersen et al., 2023).

[8] Intensity IX: "violent; Damage is considerable in specially designed structures; well-designed frame structures are thrown off-kilter. Damage is great in substantial buildings, with partial collapse. Buildings are shifted off foundations. Liquefaction occurs. Underground pipes are broken."

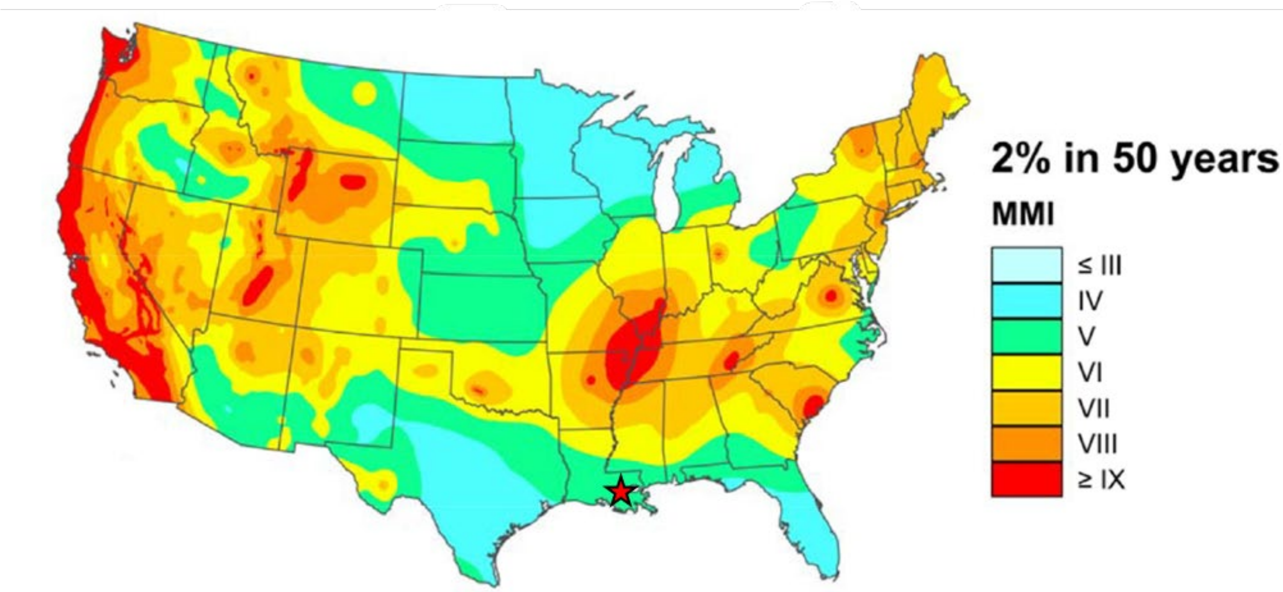

Figure 1-70 – Total mean seismic hazard map for 2% probability of occurence in 50 years; the location of the Libra project is indicated by the red star in an area capable of "V" MMI events, although unlikely (modified from Petersen et al., 2023).

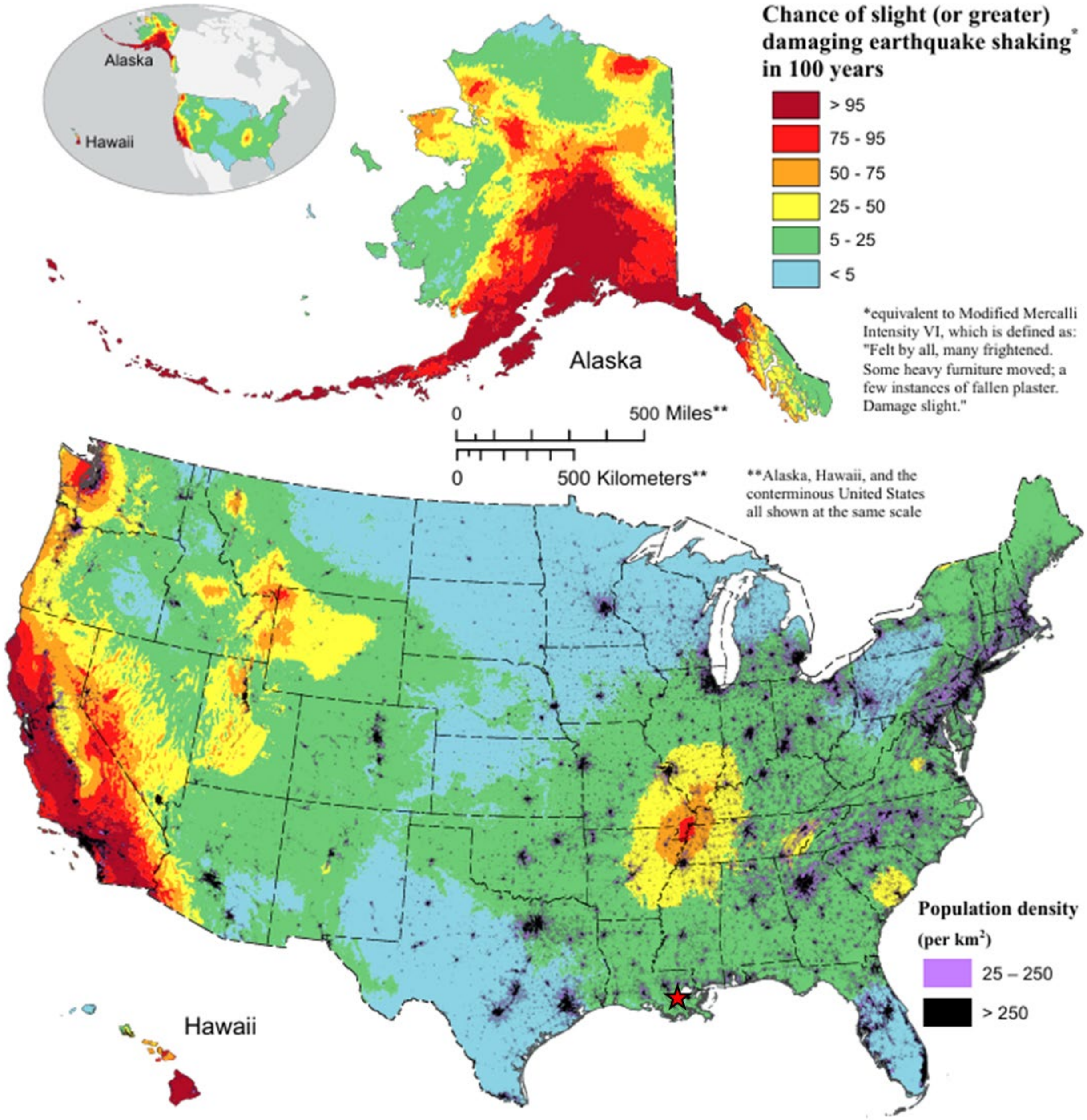

Figure 1-71 – Map showing the population density and risk of a class VI earthquake shaking in 100 years; the location of the Libra project is indicated by the red star (modified from Petersen et al., 2023).

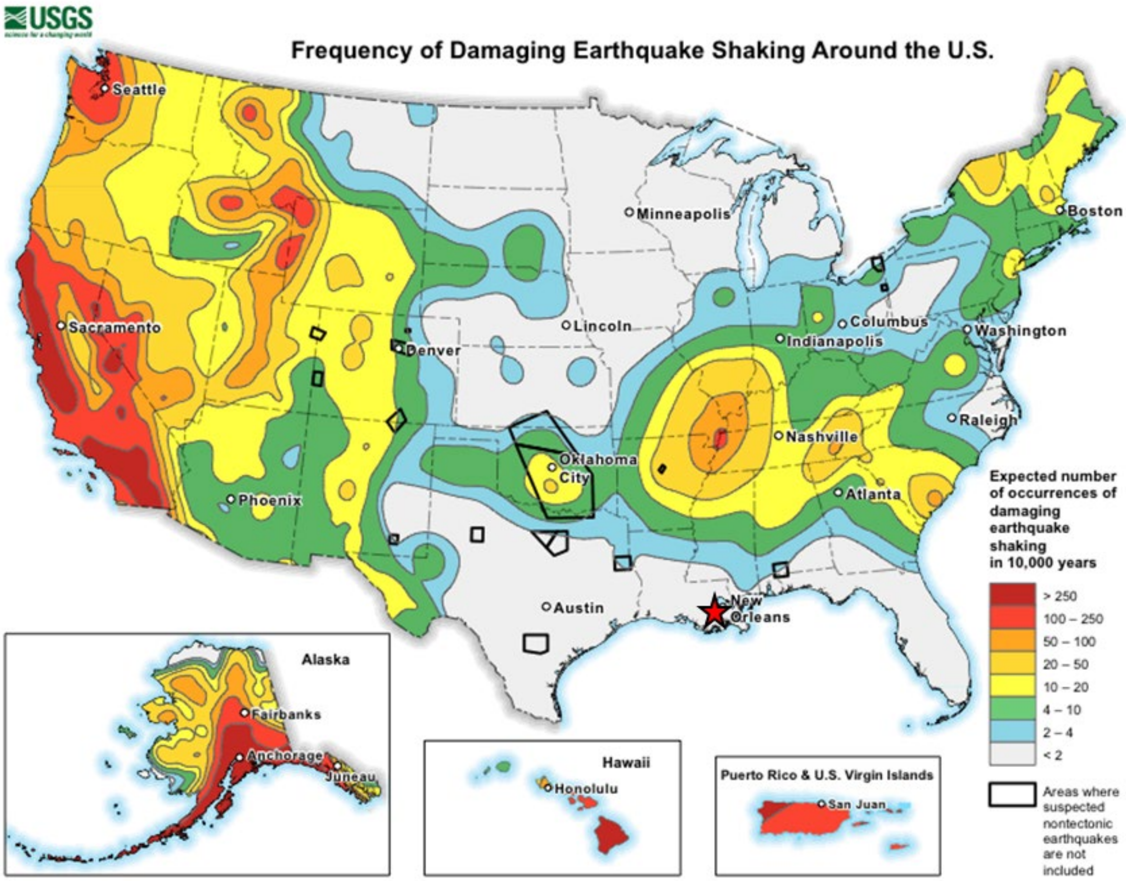

Figure 1-72 – Expected frequency of earthquake shaking induced damage in 10,000 years; the location of the Libra project is indicated by the red star in an area of <2 occurences per 10,000 years (USGS, retrieved 2024).

Fault movement caused by seismicity can have an adverse effect on surface elevations and slopes, which can affect drainage levees, hurricane evacuation, flood protection, and other natural surface features (Gagliano et al., 2003). The Federal Emergency Management Agency (FEMA) has completed a National Risk Index[9] and considers St. Charles Parish to be a “moderate risk” as shown in Figure 1-73. This risk assessment is based on multiple natural disasters (earthquakes on their own are rated “Very Low”), the degree to which the public are exposed to them (Social Vulnerability rated “Relatively Low” and Community Resilience rated “Very High”), and the susceptibility of the infrastructure and buildings (Expected Annual Loss rated “Relatively Moderate”). This rating is supported by Augurisk (2020), where St. Charles Parish received a natural disaster risk score of 60% (Moderate), with the most common natural disasters being coastal floods and hurricanes, while earthquakes only comprise approximately 14% (low risk).

[9] *Natural hazard* includes the following 18 hazards: Avalanche, Coastal Flooding, Cold Wave, Drought, Earthquake, Hail, Heat Wave, Hurricane, Ice Storm, Landslide, Lightning, Riverine Flooding, Strong Wind, Tornado, Tsunami, Volcanic Activity, Wildfire, and Winter Weather.

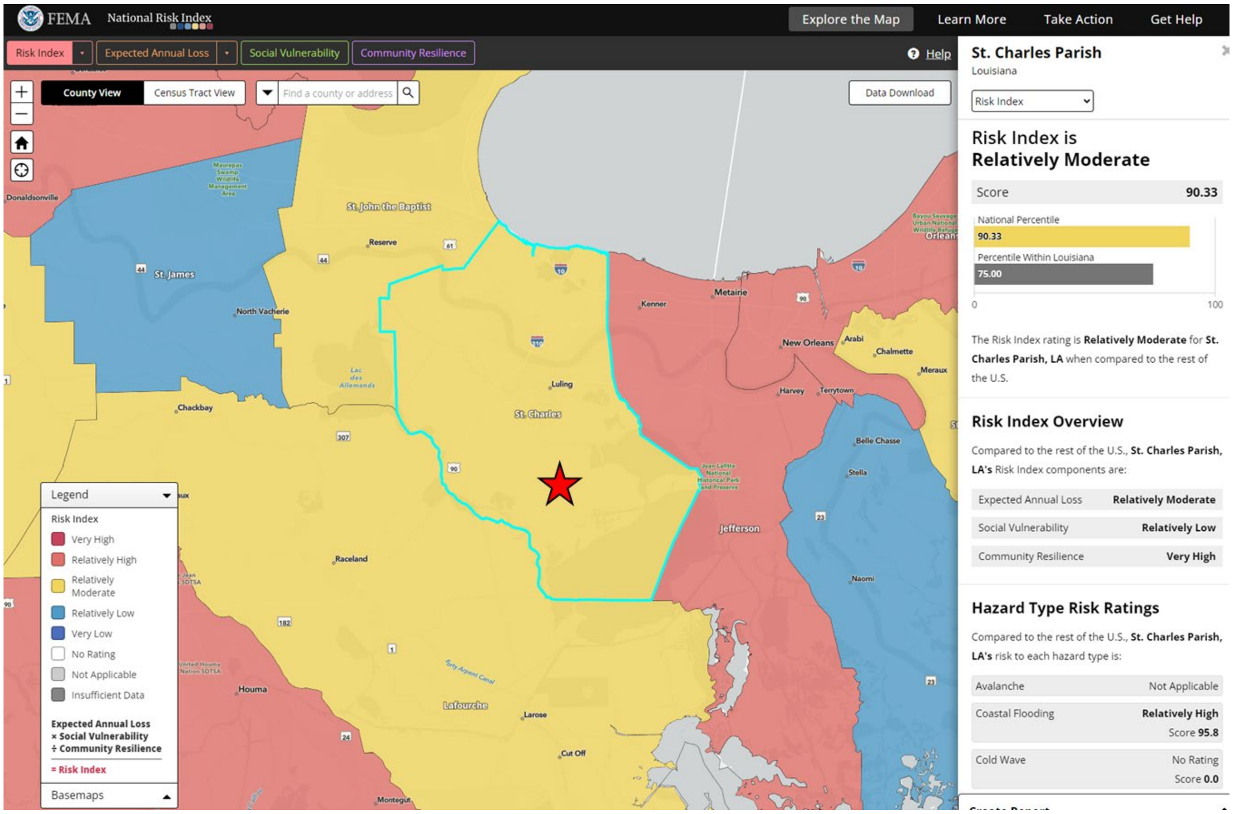

Figure 1-73 – The FEMA Risk Index Map with the location of the proposed Libra project represented by the red star (National Risk Index FEMA, 2023).

Considering the 2023 NSHM Maps and seismicity investigation, the Libra project is located in one of the U.S. regions with the least number of earthquakes. Although there is always some level of risk for earthquakes, in the vicinity of the project area they are unlikely to be any of high magnitude or any that cause any significant damage.

1.13 Conclusion

The site characterization of the proposed injection wells, Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, proves that the Upper and Middle Miocene sandstones have sufficient porosity, permeability, and lateral continuity—and are of sufficient depth and thickness to store the proposed amount of CO_2. The Rob E shale at the site location has low enough permeability, sufficient thickness, and lateral continuity of clay-rich shale to serve as the primary upper confining zone. Similarly, the Cris I shale has low enough permeability, sufficient thickness, and lateral continuity of clay-rich shale to serve as the principal lower confining zone. Potential CO_2 migration pathways in the Upper and Middle Miocene injection zones within the AOR have been identified, located, characterized, and modeled and are determined to be of low risk. Wellbores within the AOR have been identified, located, and reviewed for potential migration pathways and are also determined to be of low risk. Upon issuance of the Class VI Order to Construct, additional data will be collected, assessed, and integrated into an augmented application, to ensure that the site remains low risk for CO_2 injection and storage.

The following attachments are in *Appendix B:*

- Appendix B-1 E-W Structural Cross Section
- Appendix B-2 N-S Structural Cross Section
- Appendix B-3 Structural Cross Section Reference Map
- Appendix B-4 [redacted]
- Appendix B-5 [redacted]
- Appendix B-6 [redacted]
- Appendix B-7 [redacted]
- Appendix B-8 [redacted]
- Appendix B-9 [redacted]
- Appendix B-10 [redacted]
- Appendix B-11 Upper Confinement Gross Interval Isochore
- Appendix B-12 Injection Zone Gross Interval Isochore
- Appendix B-13 Lower Confinement Gross Interval Isochore
- Appendix B-14 Upper Confinement Net Shale Isochore
- Appendix B-15 Injection Zone Net Sand Isochore
- Appendix B-16 Lower Confinement Net Shale Isochore
- Appendix B-17 Offset Produced Water Samples Locator Map
- Appendix B-18 USDW Structural Cross Section (E-W)
- Appendix B-19 USDW Structural Cross Section (N-S)
- Appendix B-20 USDW Structure / Cross Section Reference Map
- Appendix B-21 [redacted]
- Appendix B-22 [redacted]
- Appendix B-23 [redacted]

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SECTION 2 – PLUME MODEL

TABLE OF CONTENTS

Figures

Tables

2.1 Introduction

In compliance with Statewide Order (SWO) 29-N-6, **§3615.31** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84**], the following discussion is centered on the expected plume model for the Libra CO_2 Storage Solutions Project (Libra) Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003. The dynamic reservoir model establishes the required pore space, defines the area of review (AOR), outlines comprehensive corrective action plans, and assesses the overall feasibility of the project within the specified regulatory framework. Both *Section 3 – AOR and Corrective Action Plan* and *Section 5 – Testing and Monitoring Plan* utilize the forecasted plume to help determine the best strategies and tactics to minimize the impact of this carbon sequestration project on the surrounding pore space and surface infrastructure.

The primary objectives of the plume model are as follows:

1. Maximize the utilization of available pore space for carbon sequestration activities.
2. Evaluate the most strategically optimal well locations to facilitate carbon storage.
3. Assess the migration of CO_2 and the injectors' pressure influence to prevent any adverse effects on significant subsurface structures.
4. Provide supporting data to determine corrective action and monitoring plans.

2.2 Project Summary

The Libra project, located in St. Charles Parish, Louisiana, is near an industrial corridor. The acreage is approximately 20 miles (mi) west of New Orleans. The project envisions utilizing existing infrastructure to capture and transport emissions for sequestration at a single-project carbon capture and storage (CCS) site. The Libra project targets CO_2 injection for storage into Miocene sand reservoirs, which lie approximately 4,000–10,000 feet (ft) below the surface.

2.2.1 Computational Software

Schlumberger software has been utilized to construct models that best represent the Lapis CO_2 sequestration development plans on the Libra project acreage. Data from regional sources, nearby wells, and analogues in the absence of site-specific well information are utilized to construct both the static and dynamic simulation models. Results serve as the preliminary foundation for predicting critical pressure levels and plume extents to delineate the AOR. A final simulation scenario will be developed once site-specific data from the project's stratigraphic test well and proposed injection wells become available.

2.2.2 Petrel™ Geomodeling Software (Ver. 2023.6)

Petrel software provides a collaborative environment for subsurface professionals for reservoir characterization, static and dynamic modeling, development planning, reservoir performance evaluation, and uncertainty assessment. The integration of the work processes facilitates the capture and preservation of knowledge from the geoscientist to the reservoir engineer and beyond, to generate an integrated interpretation of the subsurface. Petrel presents a comprehensive environment for pre- and post-processing simulation workflows and provides the tools needed for both the planning and monitoring of injected CO_2.

2.2.3 Intersect™ Simulation Software (Ver. 2023.4)

Intersect is Schlumberger's next-generation, high-resolution simulator designed to tackle complex reservoir modeling challenges with speed and flexibility. The advanced gridding and hybrid-parallelism features allow for efficient and accurate modeling of geological formations, ensuring that simulations can handle large data sets and complex reservoir structures. The dedicated CO_2 functionality features in Intersect, like temperature- and pressure-dependent water properties and CO_2 trapping models, are essential for accurately predicting the behavior of CO_2 in storage scenarios. Additional features include Peng-Robinson and Soave-Redlich-Kwong equation of states, Ezrokhi water-properties correlations, CO_2 solubility in water tables, diffusion, and geochemical reactions via internal procedure or by coupling with external geochemical software like PHREEQC.

This functionality supports the development of effective CCS strategies, helping to mitigate the impact of CO_2 emissions on the environment. Run time in Intersect is reduced by 7 to 20 times relative to running similar CO_2 storage cases in Eclipse 300 (E300), Schlumberger's compositional simulator. All dynamic modeling work is done in Intersect.

2.3 Dynamic Model Setup

The workflow in building a dynamic model to simulate CO2 storage consists of upscaling the fine-scale static model to a coarser grid, followed by defining boundary and initial conditions, incorporating fluid and rock properties and establishing a field management strategy. The workflow ensures that the model reflects reservoir behavior and produces consistent estimations of CO2 storage capacity and movement over time.

2.3.1 Upscaling Process

Upscaling is the process of creating a coarser grid based from the fine-scale static model with the goal of minimizing the required computational time for flow simulation (i.e., reduced number of cells in the model). The main principle of upscaling is to create an accurate representation of the fine-scaled model by the coarsened upscaled model, including the preservation of volumetrics, connectivity, and minimizing differences in flow and production profile between the fine and coarse models while improving computational efficiencies.

The upscaling process is composed of two major components: scaling-up the structural grid, and scaling-up the petrophysical properties. Scaling-up the structure creates a coarser grid where the aerial size of the cells may be enlarged and/or the number of k-layers is reduced. Scaling-up properties is the process whereby fine-scale properties are averaged or upscaled into a grid of different resolution or orientation.

For strata with homogeneous rock properties, the aerial and vertical domains can be upscaled simultaneously as the properties are similar in all directions. The simultaneous averaging in two domains minimally impacts the connectivity and flow between the fine and coarse models.

Where strata are heterogenous, a staged upscaling approach is used. First, upscaling is performed in the horizontal domain, then upscaling is performed for the vertical domain. This approach is preferred because it allows for increased control in property averaging, resulting in better preservation of the connectivity and flow between the fine and coarse models.

Listed below is the upscaling workflow performed for the Libra project:

- Stage 1a: Generate an aerially coarse-scale geocellular model (aCSGM) by enlarging cell x- and y-dimensions from the fine-scale geocellular model (FSGM).
- Stage 1b: Sample FSGM petrophysical properties into the aCSGM.
- Stage 2a: Reduce k-layers from the aCSGM using Intersect to generate the final aerially and vertically coarse-scale geocellular model (avCSGM).
- Stage 2b: Sample petrophysical properties from the aCSGM into the avCSGM.

The resultant grid and properties from the upscaling workflow, avCSGM, will be used for dynamic simulation and referred to as the coarse-scale geocellular model (CSGM) or dynamic model.

2.3.1.1 Aerial Upscaling

The FSGM, or static model, as discussed in *Section 2.3.1*, was used to generate an aerially coarsened grid to reduce the initial number of cells in the model. Petrophysical properties from the FSGM, such as net-to-gross (NTG), effective porosity (PHIE), and permeability, were sampled into the aCSGM using assorted averaging methods. The resultant aCSGM and associated properties are considered intermediary in the upscaling workflow, and were used next in the vertical upscaling stage.

Structural Upscaling

The static model is a fine-scale geocellular grid consisting of 241 x 296 x 1,302 grid blocks, resulting in a total of 92,879,472 cells with 78,816,586 active cells. Grid block x-y dimensions are 200 ft x 200 ft, and the average cell height is 6.2 ft (average cell thickness of 5 ft for the main intervals of interest within the injection zone).

The structural model was aerially coarsened in Petrel so that the cells increased from 200 ft x 200 ft to 400 ft x 400 ft in the x- and y-dimensions. The vertical number of layers stayed the same. The resultant aCSGM mesh consists of 121 x 149 x 1,302 grid blocks, resulting in a total of 23,473,759 cells. Grid block x-y dimensions are 400 ft x 400 ft, and the average cell height is 6.2 ft.

Properties Upscaling (Aerial)

Porosity, NTG, and permeability properties are sampled from the FSGM to the aCSGM using Petrel's scaling-up properties process. Only one array for horizontal permeability is provided in the fine-scale model and for simulation purposes; this array is used for all three permeability directions.

The sampling method used for property upscaling is zone-mapped layers with geometric overlap. Several averaging methods are available in Petrel for upscaling properties. The following list outlines the algorithms selected for the upscaled properties:

NTG – Volume-weighted arithmetic averaging with no weighting properties
Porosity – Volume-weighted arithmetic averaging, weighted by NTG
Permeability – Volume-weighted geometric averaging, weighted by NTG

Aerial Upscale Validation

Quality-checking the results of the upscaled properties is necessary to test the validity of the upscaling. One important consideration is the preservation of pore volumes between the fine- and coarse-scale models. After upscaling the Libra project FSGM to the aCSGM, the pore volume calculations differ by only 0.6%, with the fine-scale model having the slightly larger volume.

Histograms and statistics for the different properties are also checked to ensure that these appear similar before and after upscaling. For example, Figure 2-1 compares the histogram plots of the fine-scale (pink histogram bar) and aerially upscaled (blue histogram bar) model permeability distributions. The qualitative shapes and percentages of the distributions between the two scales are very similar, suggesting that the upscaling algorithm selected is appropriate.

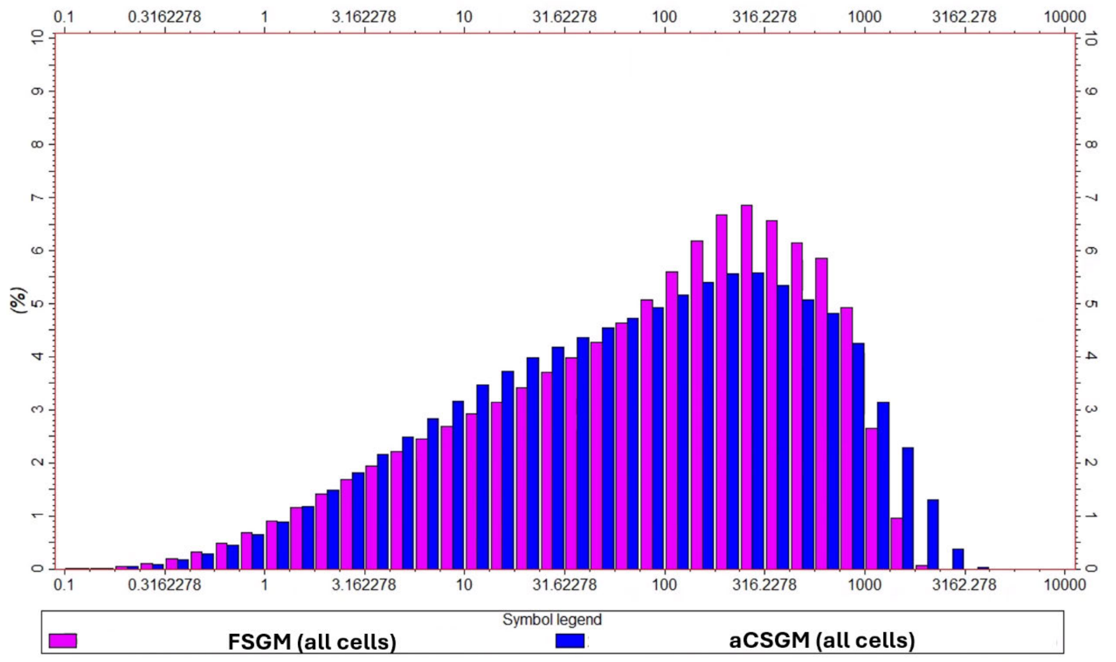


Figure 2-1 – Upscaled property comparison and validation through histograms.

Another check is a visual inspection of the fine-scale and upscaled grid properties in a Petrel well correlation section that displays the grid properties side-by-side on log track panels, as displayed in Figure 2-2. Shown there are permeability, porosity, and NTG properties on log tracks next to each other from the aCSGM with the well log. The aerial cells that were combined from the fine-scale model to create the coarse-scale model properties look very similar to the well log.

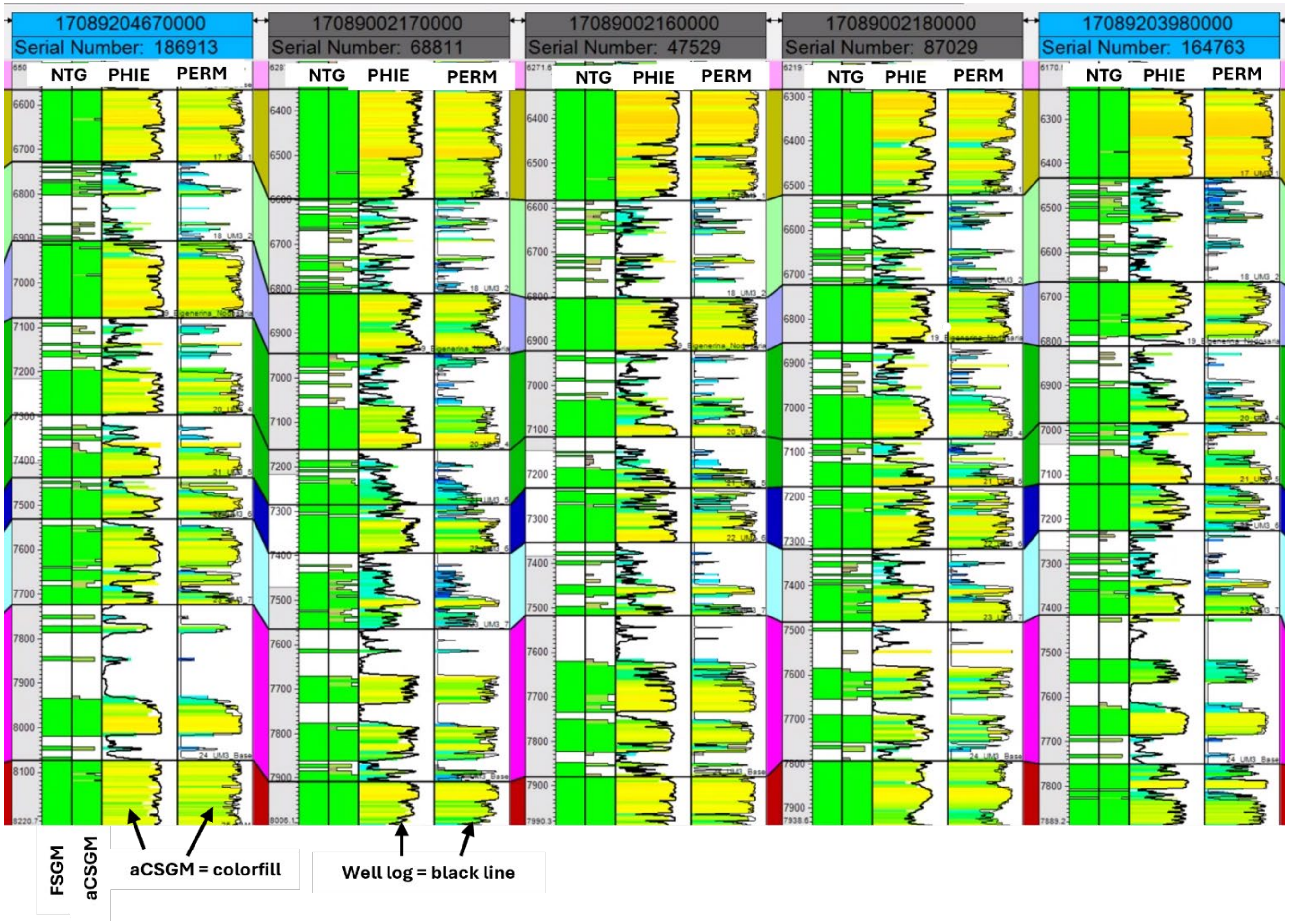


Figure 2-2 – Upscaled property validation through log track comparison.

2.3.1.2 Vertical Upscaling

The Petrel aCSGM mesh consists of 121 x 149 x 1,302 grid blocks, resulting in a total of 23,473,759 cells. Grid block x-y dimensions are 400 ft x 400 ft, and the average cell height is 6.2 ft. To reduce simulation run time and preserve the ability to conduct uncertainty analyses efficiently, the aCSGM was vertically upscaled to 121 x 149 x 475 grid blocks, resulting in 8,563,775 total grid cells—5,400,00 of which are active. The average cell height in the aerially and vertically upscaled model is 17.0 ft.

Tools and Workflow

CONNECT™, a Petrel plug-in, was utilized for the upscaling process. Developed by Kelkar & Associates, the software provides connectivity between the aCSGM and avCSGM and consists of two modules, UpGrid and TransMod. UpGrid identifies the optimum layering strategy by combining layers with similar pressure distributions first, then isolating layers with distinct pressure profiles. TransMod preserves the geologic connectivity of the aCSGM, generating transmissibility multipliers in the x- and y-directions and transmissibility in the z-direction. The workflow involves firstly generating the optimum layering with UpGrid, upscaling properties in Petrel, then generating the transmissibility multipliers with TransMod to include as properties in the simulation build.

The up-gridding process yielded an optimum layer count of 475 for the Libra project model. Table 2-1 shows the layering in the FSGM, aCSGM, and avCSGM by zone and the resultant vertically upscaled layering strategy for each zone.

Table 2-1 – Zone Layering Comparison

	FSGM, aCSGM			avCSGM		
Zone	Top layer	Base layer	# of Layers	Top layer	Base layer	# of Layers
01_Top_Grid	1	25	25	1	17	17
02_UCZ	26	55	30	18	22	5
03_Top_Miocene	56	80	25	23	41	19
04__3514	81	105	25	42	59	18
05__3218	106	130	25	60	80	21
06_UM1_1	131	185	55	81	104	24
07_UM1_2	186	240	55	105	129	25
08_UM1_Base	241	280	40	130	137	8
09__3010	281	320	40	138	156	19
10_Cristell_K	321	395	75	157	190	34
11_UM2_1	396	445	50	191	206	16
12__2812	446	490	45	207	226	20
13__2760	491	505	15	227	235	9
14__2728	506	550	45	236	256	21
15_UM2_2	551	625	75	257	278	22
16_UM2_Base	626	695	70	279	316	38
17_UM3_1	696	745	50	317	322	6
18_UM3_2	746	810	65	323	340	18
19_Big_Nod	811	845	35	341	350	10
20_UM3_4	846	870	25	351	358	8
21_UM3_5	871	890	20	359	366	8
22_UM3_6	891	930	40	367	374	8
23_UM3_7	931	975	45	375	382	8
24_UM3_Base	976	1035	60	383	409	27
25_UM4	1036	1065	30	410	413	4
26_MidMio	1066	1090	25	414	427	14
27_MM1_1	1091	1110	20	428	428	1
28_MM1_2	1111	1111	1	429	429	1
29_MM1_Base	1112	1141	30	430	437	8
30_MM2_1	1142	1142	1	438	438	1
31_MM2_Base	1143	1162	20	439	449	11
32__1892	1163	1212	50	450	463	14
33_LCZ	1213	1262	50	464	466	3
34_Bottom_Grid	1263	1302	40	467	475	9
Total			1302			475

Properties Upscaling (Vertical)

Porosity, NTG, and permeability properties are sampled from the aCSGM to the avCSGM using Petrel's scaling-up properties process. Only one array for horizontal permeability is provided in the fine-scale model and for simulation purposes; this array is used for all three permeability directions.

The sampling method used for property upscaling is source cell centers with geometric overlap. Several averaging methods are available in Petrel for upscaling properties. The following list outlines the algorithms selected for the upscaled properties:

Porosity – Volume-weighted arithmetic averaging, weighted by NTG
NTG – Volume-weighted arithmetic averaging with no weighting properties
Permeability – Finite-difference, flow-based upscaling

Vertical Upscale Validation

Quality-checking the results of the upscaled properties is necessary to test the validity of the upscale. One important consideration is the preservation of pore volumes between the aCSGM and avCSGM. After upscaling the Libra project's aCSGM, the pore volume calculations between the aerially and vertically upscaled models differ by 1.4%, with the aCSGM model having the slightly larger volume.

Histograms and statistics for the different properties are also checked to ensure that these appear similar before and after upscaling. For example, Figure 2-3 compares the histogram plots of the aCSGM and avCSGM permeability distributions. The qualitative shapes of the distributions between the two scales are very similar, suggesting that the upscaling algorithm selected is appropriate.

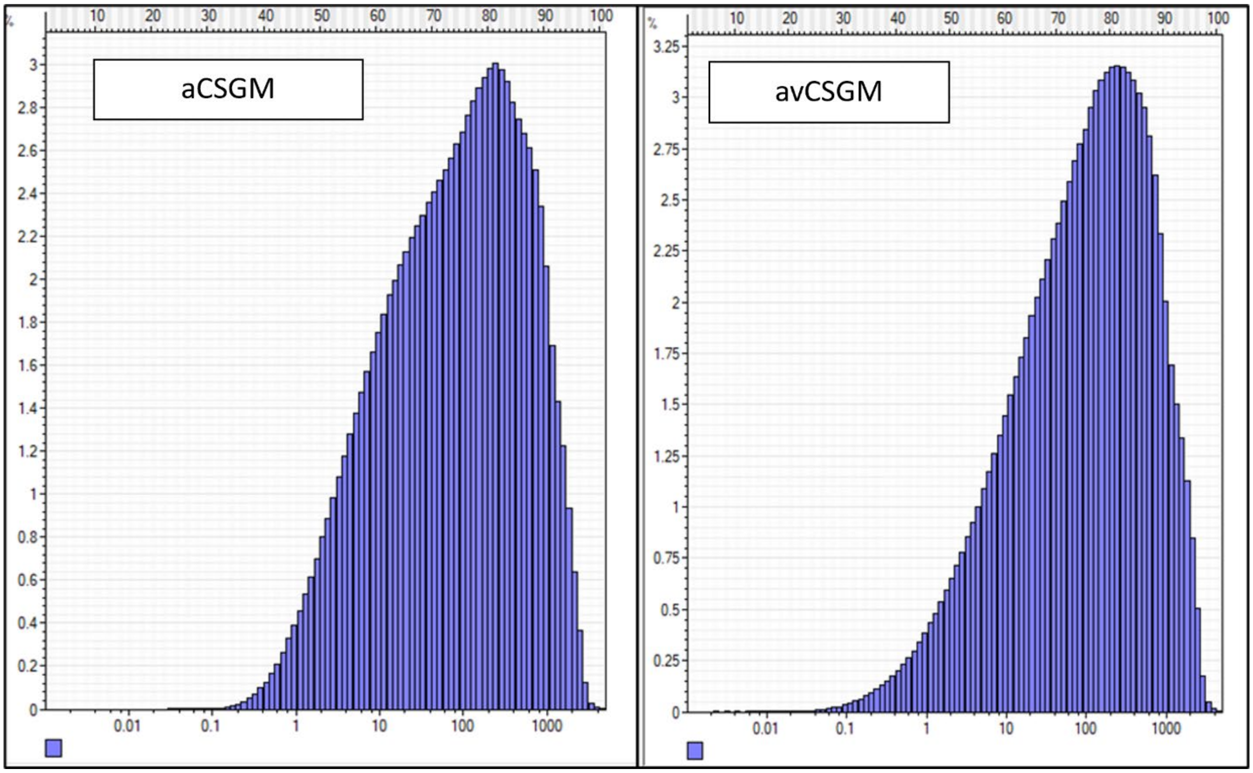


Figure 2-3 – Upscaled property validation through histogram comparison.

Another check is a visual inspection of the aCSGM and avCSGM grid properties in a Petrel well correlation section that displays the grid properties side-by-side on log track panels, as displayed in Figure 2-4. Shown there are permeability, porosity, and NTG properties for a well from the aCSGM and avCSGM on log tracks next to each other. The layers that were combined from the aCSGM to create the avCSGM properties look very similar.

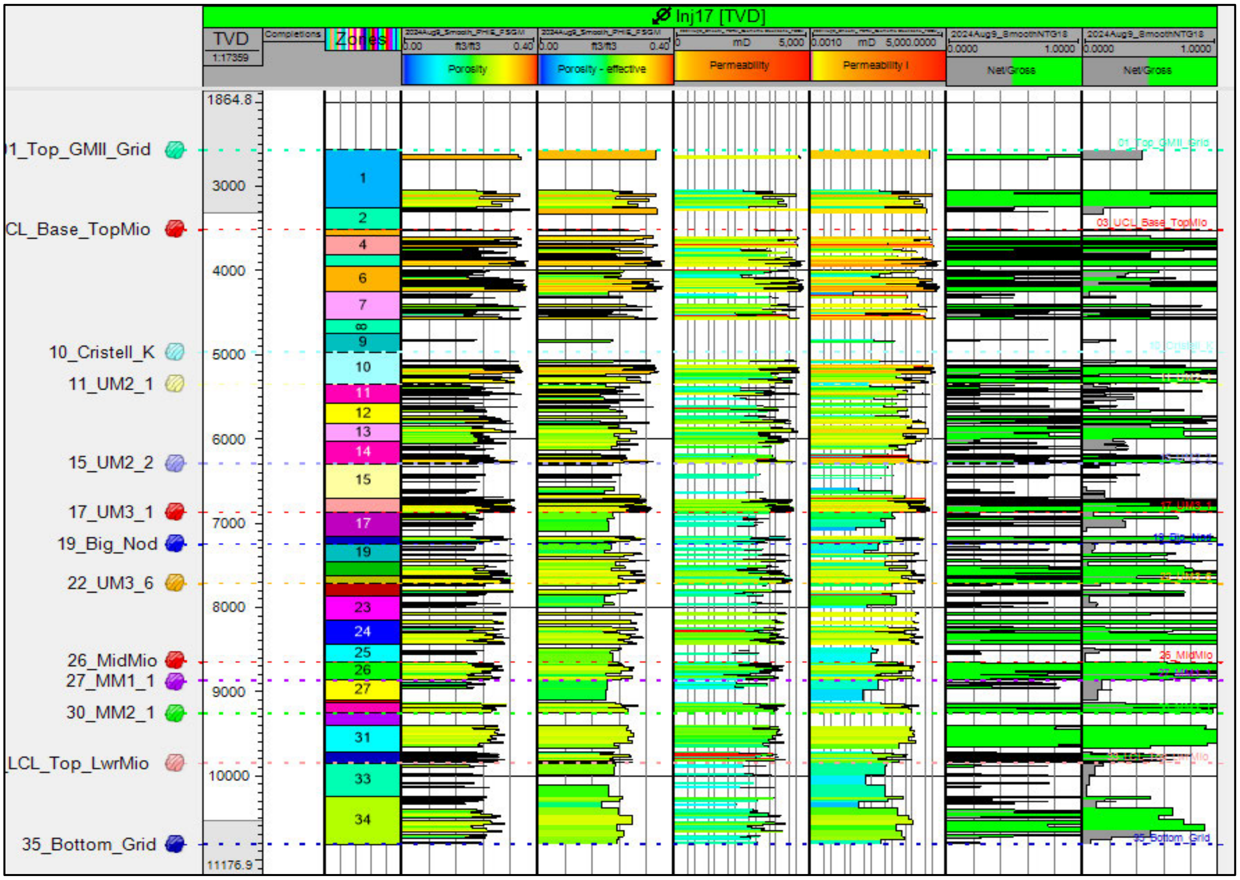


Figure 2-4 – Upscaled log track property validation at an injector location.

To further validate the upscaling, runs were made with both the aCSGM and avCSGM models, using the same boundary conditions and injection strategy for each case. Results shown in the plot in Figure 2-5 indicate good agreement between both scale models, with the major difference being simulation run time. The aCSGM model took approximately four times as long to run as the avCSGM. The much shorter run time makes the upscaled model far more suitable to conduct sensitivities, like well-location testing and injection-rate permutations.

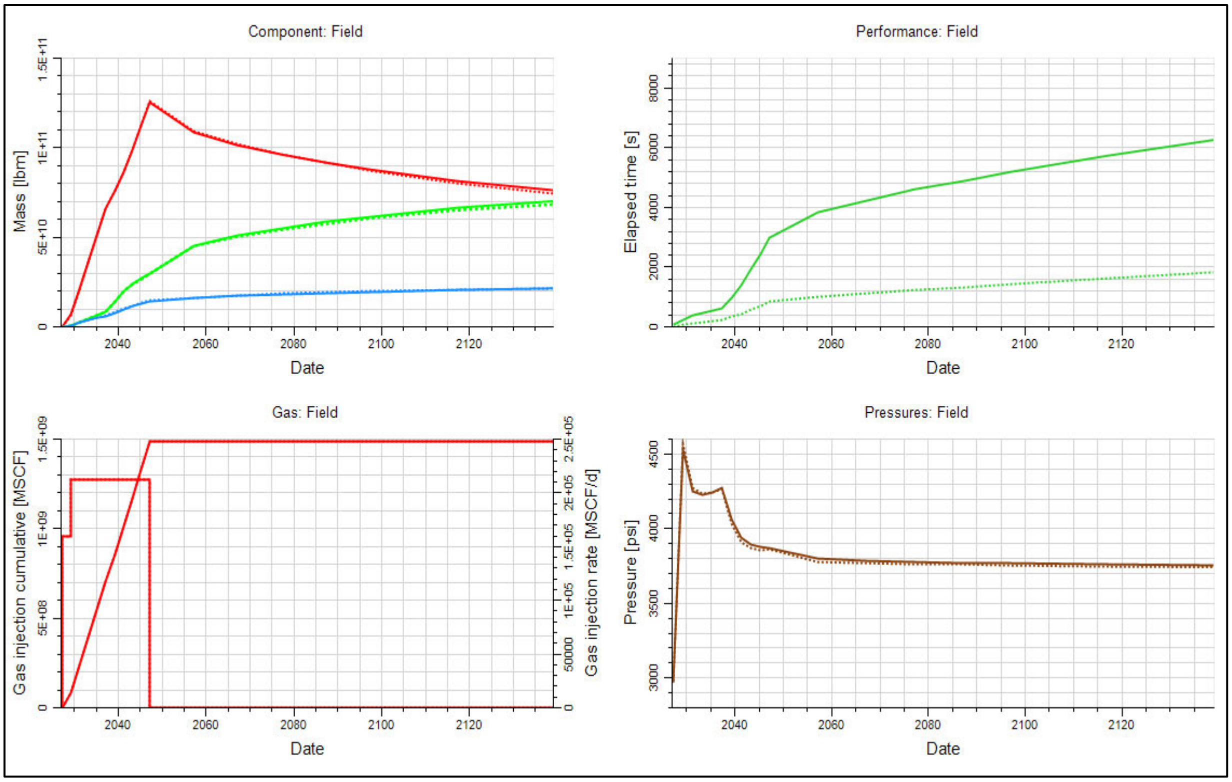


Figure 2-5 – Upscaled field performance validation.

The last check is to compare the critical pressure fronts and maximum extent of the plume areas of both cases. Figure 2-6 shows the plume (gas saturation >3%) at the end of simulation (200 years post-injection) for both the aCSGM and avCSGM. The blue and green polygons represent the aCSGM and avCSGM plumes, respectively. Figures 2-6 and 2-7 are shown only as validation of the upscaling process. The final model results are summarized in *Section 2.5*.

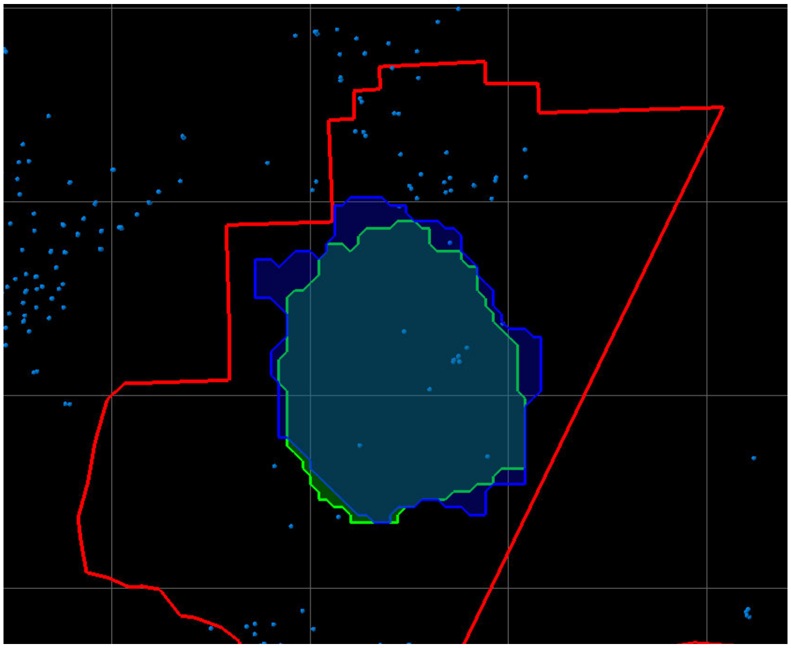


Figure 2-6 – Upscaled CO_2 plume validation (200 Years Post-Injection).

Figure 2-7 compares the critical pressure fronts for both cases (the aCSGM in blue; avCSGM in green), indicating a good match.

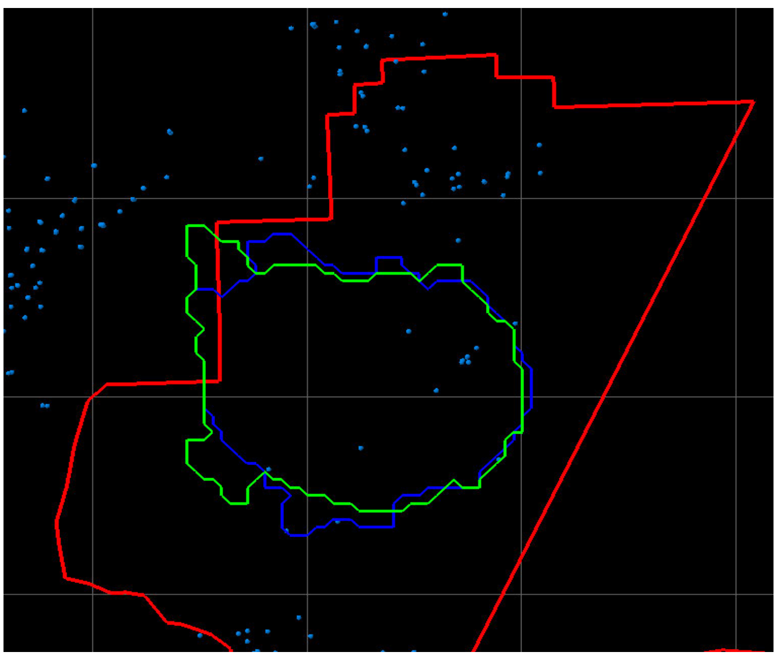


Figure 2-7 – Upscaled pressure front validation.

2.3.2 Boundary Conditions

Boundary conditions define the behavior at the edges of the modeled reservoir system, influencing how fluids move within the reservoir. These conditions are crucial in determining how pressure, flow rates, and saturation levels evolve over time.

A Carter-Tracy analytical aquifer model was chosen as the Libra project model boundary conditions. This aquifer model is based on a fully transient aquifer that requires the relationship of dimensionless pressure and time (influence functions) to predict aquifer response. Response types may be infinite, finite, constant terminal pressure, or rate. An extensive regional aquifer is expected in the project area, as the model area sits within a large basin that potentially provides support beyond the model boundaries. The model area is approximately 87 square miles (sq mi) with an equivalent reservoir radius of 28,000 ft.

Three aquifers are attached to all four grid edges, each of which are connected to the intervals into which injection occurs, as illustrated in Figure 2-8. Connections for the three aquifers are represented by the orange, pink, and purple colors around the grid. No aquifer is attached to the upper zones above Zone 10_Cristell_K (Horizon Cristellaria K). There is no need for an aquifer to be modeled above Zone 10_Cristell_K, as no injection activity is planned for these shallower zones. A detailed injection plan is provided in *Section 2.4.8.2*. Aquifer properties are summarized in Table 2-2.

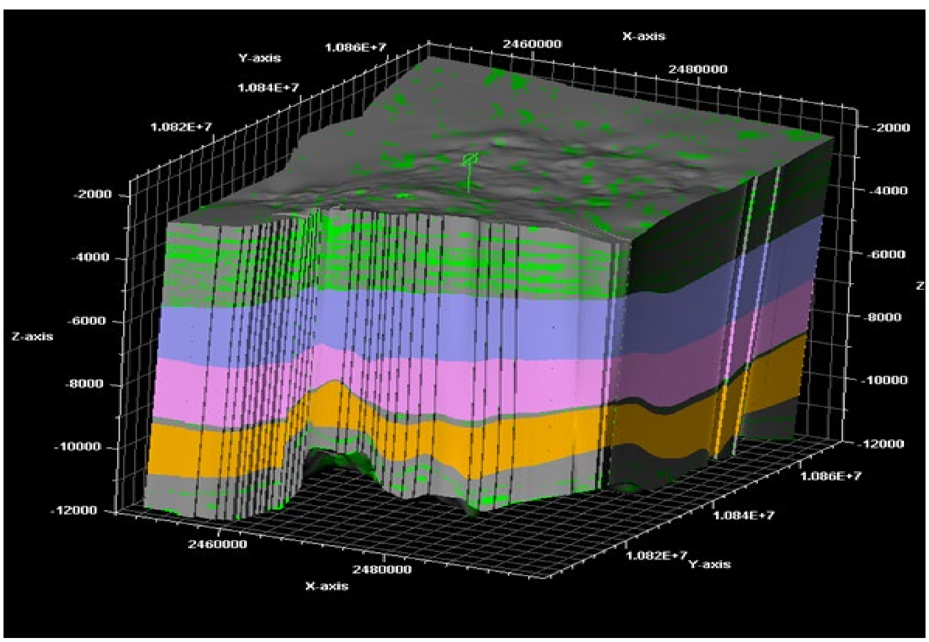


Figure 2-8 – Modeled attached aquifer 3D view.

Table 2-2 – Carter-Tracy Aquifer Properties

Carter-Tracy Aquifer Properties			
Aquifer No.	1	2	3
Permeability (mD)	200	200	200
Porosity (%)	25	25	25
Total Compressibility (1/psi)	1E-5	1E-5	1E-5
Influence Function Table	5	5	5
Encroachment Angle (degrees)	360	360	360
Aquifer Radius (feet)	150,000	150,000	150,000
Thickness (ft)	1,700	850	1,700
Attached Zones	26 - 32	17 - 24	10 - 16

*mD – millidarcy

Figure 2-9 displays the model area (red polygon) and where it sits in the Barataria Basin (green polygon). The blue circles represent different radii, with the smallest circle radius of approximately 6 mi representing the equivalent model area, and the two larger circles representing aquifer radii of 19 mi (Aquifer 2) and 28 mi (Aquifers 1 and 3). Note that the Barataria Basin outline is bounded by the Mississippi River in the north—and the Miocene depositional system in which the Libra project is located actually extends well north of the Mississippi River, as well as to the south of the basin polygon outline.

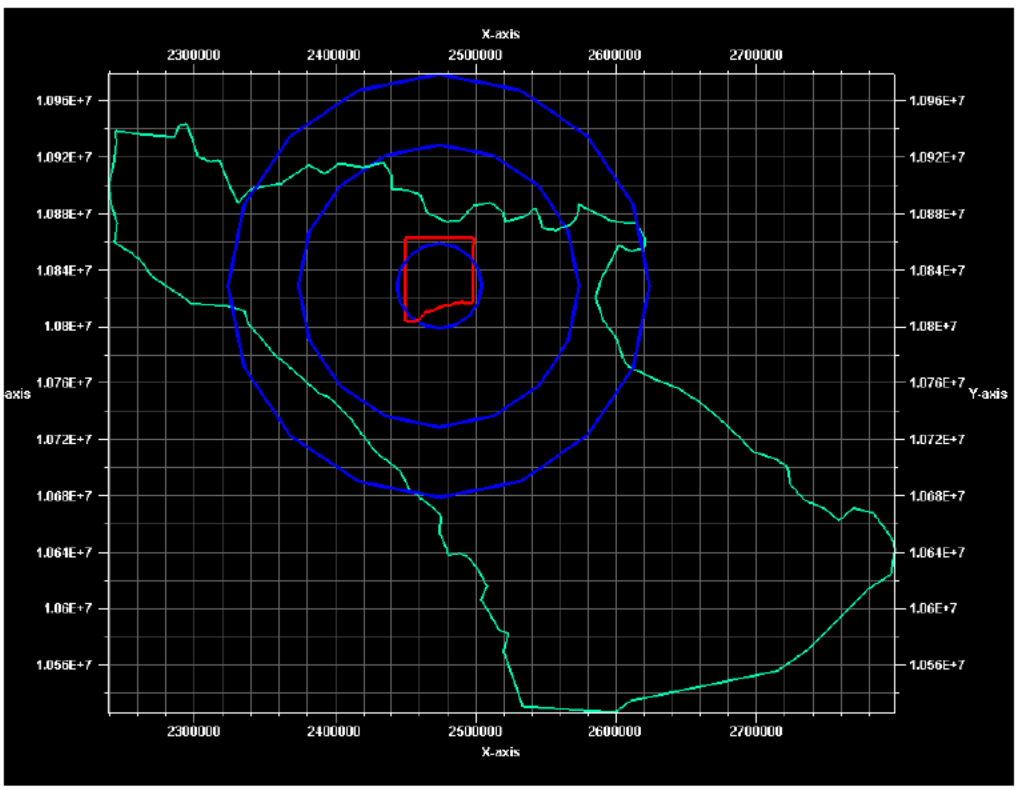


Figure 2-9 –Equivalent aquifer radii comparison.

2.3.3 Fault Modeling

Thirteen faults are modeled, and most of these faults can be traced beyond the model boundaries (Figure 2-10). The group of faults in the south extend throughout the entire injection interval, and two of these faults form the model southern boundary. Geologically, the northern group of faults extend only to the top of Zone 31 and do not exist above this zone. Petrel software require that faults included in the grid must extend to the top and base of the model, even if the faults do not geologically exist through the entire model interval. The modeled fault planes for the northern faults, which extend throughout the entire injection intervals, are still exported from Petrel to the simulation model and must be dealt with insofar as their transmissibilities. The base case is that all model faults are transmissible.

[redacted]

Figure 2-10 – [redacted]

2.3.4 Initial Conditions

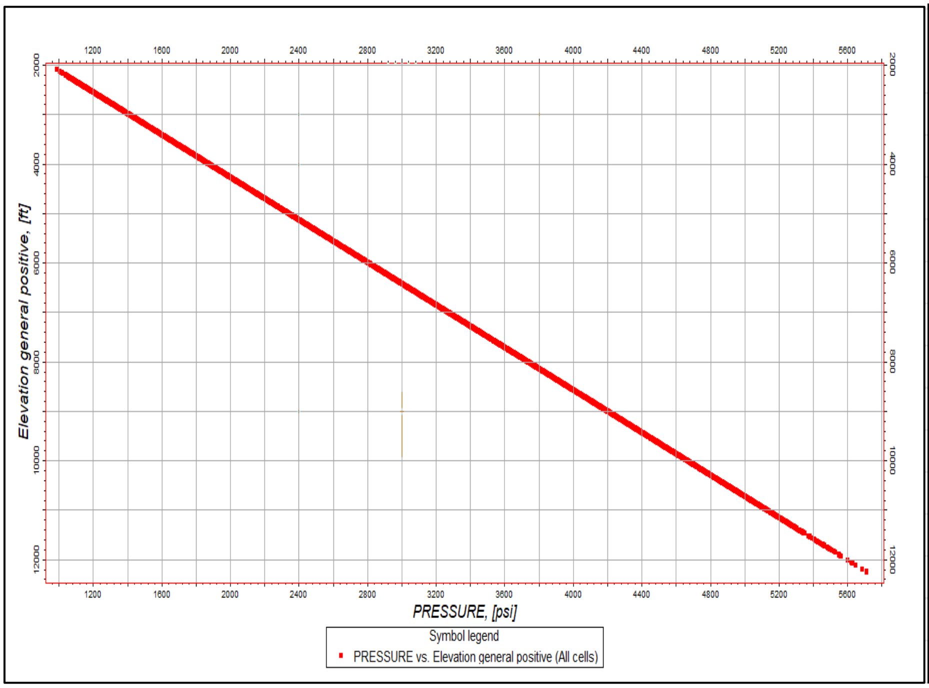
Initial conditions refer to the specific values or settings with which a model starts before simulation begins. These conditions are crucial because they set the stage for how the model will behave and evolve over time. Some of the key components include pressure, temperature, saturations, and fluid compositions.

Together, these initial conditions define the initial state of the model, providing a baseline from which the model's dynamics can be simulated and analyzed. Pressures and temperatures for the

Libra project model are discussed in the following two sections. The model is 100% saturated with brine, and the fluid composition is discussed further in *Section 2.4.6*.

2.3.4.1 Reservoir Pressure Gradients

The normal hydrostatic pressure gradient for freshwater is 0.433 pounds per square inch per foot (psi/ft) and 0.465 psi/ft for typical Gulf Coast water with 100,000 parts per million (ppm) total dissolved solids (TDS). The avCSGM horizon depths range from 1,872 ft to 11,791 ft. Initial static pressures for the model are determined using typical Gulf Coast water gradients, and—based on this—the model pressure range is 897–5,488 psi. A pressure vs. depth plot is shown in Figure 2-11.

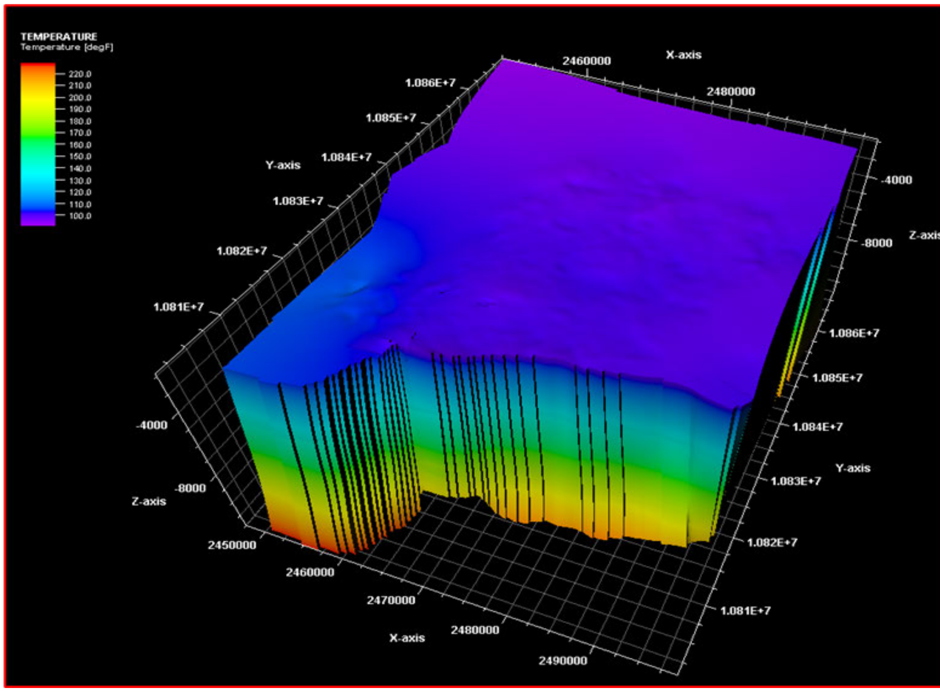


Depth	Pressure
ft	psi
0	14.4
1000	479.4
2000	944.4
3000	1409.4
4000	1874.4
5000	2339.4
6000	2804.4
7000	3269.4
8000	3734.4
9000	4199.4
10000	4664.4
11000	5129.4
12000	5594.4

Figure 2-11 – Model initial pressure gradient as a linear function.

2.3.4.2 Reservoir Temperature

Temperature gradient is also derived from the Bureau of Economic Geology (BEG) core database, sourced from Lafourche Parish, Louisiana; analogues; and available log data (Loucks, 2023). Based on data closest to the project area, a best-fit line through the temperature yields a gradient of 1.4˚F/100 ft. The surface temperature is 64˚F. Based on the temperature gradient, the model temperature ranges from 90–230˚F, although the temperature range for the targeted injection interval (Zones 10 through 32) is 135–202˚F (Figure 2-12).



Temperature Function	
Depth	Temperature
ft	F
0	64
1000	78
2000	92
3000	106
4000	120
5000	134
7000	162
9000	190
10000	204
11000	218
13000	246
14000	260
15000	274

Figure 2-12 – 3D-modeled temperature property using temperature function, model initial temperature gradient.

2.3.5 Fracture Pressure Gradient

Fracture gradient (FG) was estimated using Eaton's equation, which is commonly accepted as the standard practice in the Gulf Coast. The calculation requires Poisson's ratio (v), overburden gradient (OBG), and pore pressure gradient (PG), as shown further below in Equation 1. The input variables used in the analysis will be updated once site-specific data from the Class V stratigraphic test well becomes available.

Fracture gradients were calculated at two true vertical depths (TVDs) of 3,500 ft and 8,500 ft using Eaton's equation. These values were then interpolated to produce an FG curve that varies linearly with depth. This linear approach is validated by the findings of Althaus (1977), which utilized data from South Louisiana and offshore. The study demonstrated that FGs increase linearly with depth within the normal fluid pressure window, providing confidence in the interpolation method used for constructing the FG curve.

Poisson's ratio values were derived using Figure 2-13 (Eaton, 1969), which illustrates how Poisson's ratio varies with depth across typical Gulf Coast lithologies. The values of Poisson's ratio obtained were 0.32 at a depth of 3,500 ft TVD and 0.41 at 8,500 ft TVD.

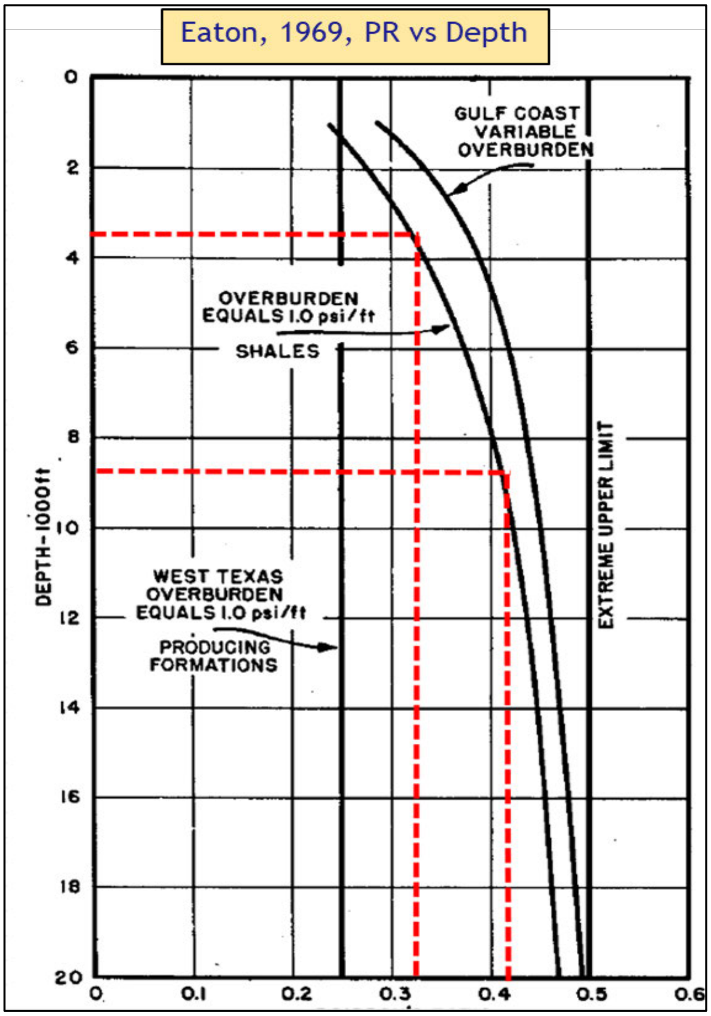


Figure 2-13 – Variation of Poisson's Ratio with Depth (Eaton, 1969)

The OBG was estimated as outlined in *Section 1 – Site Characterization*, *Section 1.7.3*, by integrating bulk density log measurements with the specified depths. The calculated OBGs were 0.91 psi/ft at a depth of 3,500 ft TVD and 1.02 psi/ft at 8,500 ft TVD.

A pore pressure gradient of 0.465 psi/ft was used, based on hydrostatic pressure trends observed across several South Louisiana fields, as documented by Nelson (2012). Sources for pressure trends in this study include drill stem tests (DSTs), mud weights, and bottomhole pressure data.

Applying Eaton's equation with an overburden gradient of 0.91 psi/ft and a Poisson's ratio of 0.32 at a depth of 3,500 ft TVD yields an estimated fracture gradient of 0.67 psi/ft, as demonstrated in Equation 1.

(Eq. 1)

$$FG = \frac{n}{1-n}(OBG - PG) + PG$$

$$FG = \frac{0.32}{1-0.32}(0.91 - 0.465) + 0.465 = 0.67\, psi/ft$$

$$FG\ with\ SF = 0.67 \times 90\% = 0.62\, psi/ft$$

Similarly, at a depth of 8,500 ft TVD, using an OBG of 1.02 psi/ft and a Poisson's ratio of 0.41 results in an estimated FG of 0.85 psi/ft. The calculations are further summarized in Table 2-3.

Table 2-3 – Fracture Gradient Calculation Inputs and Results

Depth (ft, TVD)	Zone	Formation	Overburden Gradient (psi/ft)	Pore Pressure (psi/ft)	Poisson's Ratio	Fracture Gradient (psi/ft)
3,500	Injection	Upper Miocene	0.91	0.465	0.32	0.67
8,500	Injection	Middle Miocene	1.02	0.465	0.41	0.85

The FG (psi/ft) curve generated as a linear function of feet (TVD) using the two data points above, was as follows in Equation 2:

(Eq. 2)

$$FG = 0.544 + 3.6e^{-5} \times TVD$$

The FG curve calculated above was applied across all lithologies and will be updated as more site-specific data becomes available. Since Poisson's ratio is generally higher in shales than in sandstones, the current calculation represents a conservative estimate of the FG in the shale and confining zones.

Per SWO 29-N-6, **§3621.A.1** [40 CFR **§146.88(a)**], a safety factor of 90% is applied to the calculated fracture pressure as the maximum bottomhole pressure (BHP) at any given injection interval, and is used as the well bottomhole pressure constraint for all injection wells in the model.

A more detailed summary about the FG calculations and assumptions is available in *Section 1 – Site Characterization*, *Section 1.7.3*.

2.3.6 Reservoir Fluid Model

Fluid models play a pivotal role in understanding and optimizing the CO_2 behavior when injected into the subsurface. These models simulate the physical and chemical interactions between CO_2, the surrounding brine, and the geological matrix—essential for predicting the fate of CO_2 over time.

The fluid model for the Libra project dynamic model was built with Petrel's Make Fluid Model process. The latest Intersect version contains enhanced CO_2 storage modeling functionalities relative to earlier versions, including predefined templates for CO_2 injection into saline aquifers that can be modified for specific conditions. The model is a two-component compositional fluid model (CO_2 and NaCl) that uses the Peng-Robinson equation of state (EOS) and an internal library of EOS parameters for each component (Table 2-4). The injection stream assumes 100% CO_2.

Table 2-4 – Model Reservoir Fluid Components.

Name	Origin	Molecular Weight	Critical Temperature	Critical Pressure
CO_2	Petrel Library (CO_2)	44.01	548.46	1,071.3347
NaCl	Petrel Library (NaCl)	58.443	-	-

2.3.6.1 Brine Salinity

Dissolution of CO_2 in the aqueous solution is a trapping mechanism. Lower-salinity brines tend to dissolve more CO_2, while higher salinity brines result in less dissolved CO_2. Intersect allows CO_2 solubility phase behavior to be input via component solubility tables during the Petrel Make Fluid Model process. Component solubility tables are generated and input into a variable design table that spans the appropriate temperature and salinity combinations, such as those shown in Figure 2-14. The variable design table is useful if there exists a wide range of temperature-salinity combinations within the model, as in the Libra project. The default brine model used for saline aquifers to compute the density of brine is Ezrokhi, commonly used in reservoir simulations. It provides an approximation for the density of brine based on the salt concentration and CO_2.

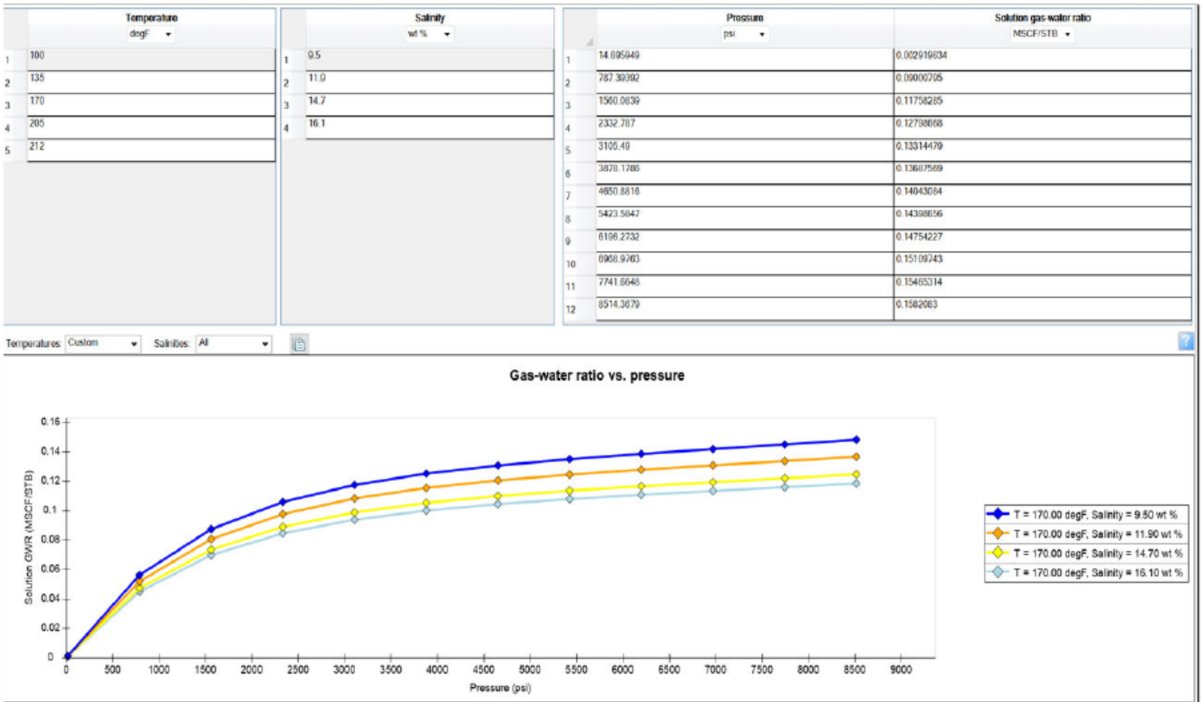


Figure 2-14 – Solubility data as used in the model.

Salinities are calculated from a couple of offset wells—SN 197891 and 125786—then plotted according to depth, displayed in Figure 2-15.

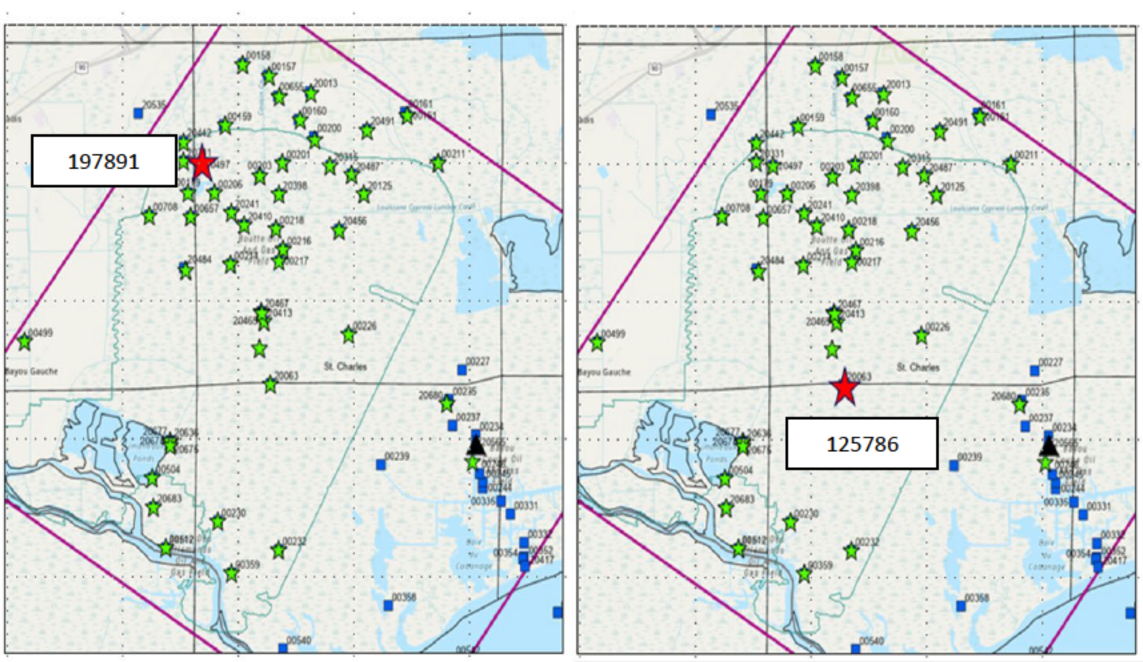


Figure 2-15 – Offset wells used for salinity estimation.

Figure 2-16 is showing the regional salinity measurements. There is quite some variation and no clear relationship with depth. However, over the injection zone depth interval there is a clear clustering around 100,000–150,000 ppm TDS.

Due to the uncertainty in the salinity trend, only a single salinity concentration is used to represent the fluid model. The value chosen, based on Figure 2-16, is 125,000 ppm—a reasonable general approximation for the entire injection zone.

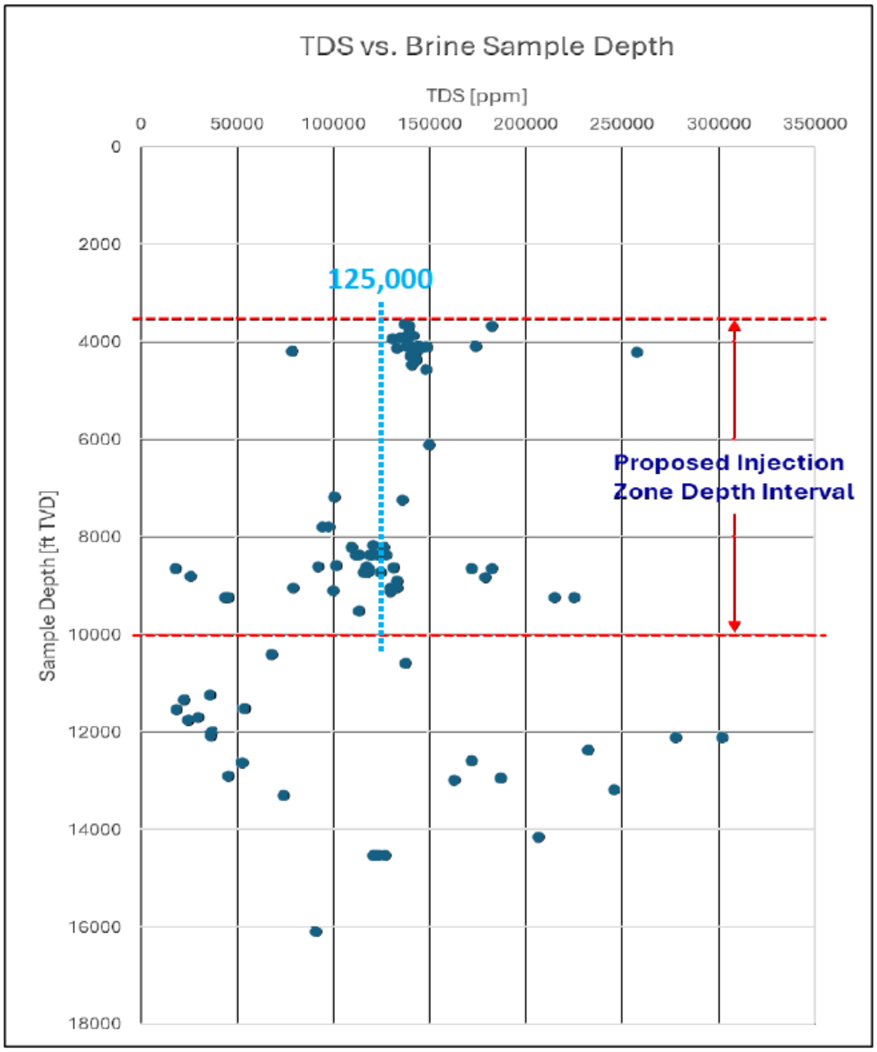


Figure 2-16 – Plot of TDS (ppm) vs. depth (ft) of nearby produced brine samples.

2.3.7 Dynamic Rock Properties

Simulation of dynamic rock properties is crucial in understanding and predicting the behavior of subsurface formations under various conditions. Properties like rock compressibility and saturation functions change over time and are influenced by factors like pressure, temperature, and fluid flow. Rock compressibility measures the rock volume changes in response to pressure variations and can be essential for predicting reservoir behavior under different production scenarios. Relative permeability and capillary pressure (saturation functions) describe how fluids are distributed within the pore spaces of the rock and their displacement processes. This is crucial for understanding how fluids move and interact within the reservoir.

2.3.7.1 Rock Compressibility

Pore volume compressibility (C_f) quantifies the rate of change in pore volume per unit change in pressure, measuring how compressible the pore space within the rock is. When pore pressure increases due to fluid injection, the rock compresses, reducing its pore volume. Conversely, when pore pressure decreases due to fluid production, the rock expands, increasing its pore volume. A large pore volume compressibility allows pore pressure changes to propagate more effectively across the entire pore system. This facilitates fluid movement through the rock. Different rock types exhibit varying pore volume compressibility based on their textural components (grain size, cementation, and pore connectivity).

The Miocene sands are characterized as friable sands, and rock compressibility is calculated as such. Because no site-specific rock compressibility information currently exists, this rock property was estimated using Yale's correlations (Yale et al., 1993), in Equation 3:

(Eq. 3)

$$c_f = A * (\sigma - B) * C + D$$

where parameters A, B, C, and D are rock type-curve dependent constants obtained from literature.

The constants for consolidated and friable sandstones are summarized in Table 2-5:

Table 2-5 – Rock Type Compressibility Constants

Type Curves				
Rock Type	A	B	C	D
Consolidated Sandstones	-2.4E-05	300	0.0623	0.00004308
Friable Sandstones	0.000105	500	-0.225	-0.00001103

Sigma (σ), a component to Equation 3, is calculated by Equation 4:

(Eq. 4)

$$\sigma = K1 * (overburden\ stress) - K2 * pi + K3 * (pi - p)(psi)$$

The K constants are also rock type-curve dependent and summarized in Table 2-6. Overburden and pressure gradients are 0.995 psi/ft and 0.45 psi/ft, respectively.

Table 2-6 – Sigma Parameters

Sigma Parameters			
Rock Type	K1	K2	K3
Consolidated Sandstones	0.85	0.8	0.45
Friable Sandstones	0.9	0.9	0.6

Rock compressibility is calculated by depth and summarized in Table 2-7. For the dynamic model, compressibility is entered as the average calculated rock compressibilities of approximately 6e-06 psi $^{-1}$ for the entire injection interval.

Table 2-7 – Calculated compressibility and parameters by depth.

TVD	overburden stress	pi	p	Sigma	Cf
ft	psi	psi	psi	psi	$x10^{-6}$ psi^{-1}
1500	1492.50	675.00	675	735.75	1.98E-05
2000	1990.00	900.00	900	981	1.523E-05
2500	2487.50	1125.00	1125	1226.25	1.291E-05
3000	2985.00	1350.00	1350	1471.5	1.139E-05
3500	3482.50	1575.00	1575	1716.75	1.028E-05
4000	3980.00	1800.00	1800	1962	9.422E-06
4500	4477.50	2025.00	2025	2207.25	8.72E-06
5000	4975.00	2250.00	2250	2452.5	8.133E-06
5500	5472.50	2475.00	2475	2697.75	7.629E-06
6000	5970.00	2700.00	2700	2943	7.19E-06
6500	6467.50	2925.00	2925	3188.25	6.802E-06
7000	6965.00	3150.00	3150	3433.5	6.456E-06
7500	7462.50	3375.00	3375	3678.75	3.281E-06
8000	7960.00	3600.00	3600	3924	3.107E-06
8500	8457.50	3825.00	3825	4128.875	2.97E-06
9000	8955.00	4050.00	4050	4371.75	2.816E-06
9500	9452.50	4275.00	4275	4614.625	2.67E-06
10000	9950.00	4500.00	4500	4857.5	2.532E-06
10500	10447.50	4725.00	4725	5100.375	2.401E-06
11000	10945.00	4950.00	4950	5343.25	2.275E-06
11500	11442.50	5175.00	5175	5586.125	2.156E-06
12000	11940.00	5400.00	5400	5829	2.041E-06
12500	12437.50	5625.00	5625	6071.875	1.931E-06
13000	12935.00	5850.00	5850	6314.75	1.825E-06

2.3.7.2 Relative Permeability Curves

Relative permeability values are typically determined through laboratory experiments using core samples from the target formation. However, site-specific information is not currently available for use in the model. Therefore, published CO_2-brine relative permeability measurements for fluvial-deltaic sandstones were used as analogues to define the Corey-Brooks parameters. Corey-Brooks exponents of 2.5 and 4.0 are used to generate the mid-case drainage curves for CO_2 and brine, respectively. Published end-point saturations (S_{wirr}) and corresponding $KrCO_2$

measurements depend on the testing techniques employed. Unsteady-state relative permeability tests have been observed to achieve the maximum immiscible displacement (i.e., max S_{CO2}).

Table 2-8 summarizes end points used for base case relative-permeability drainage curves.

Table 2-8 – End Points Summary Table

End Points	Base Case
N_{CO2}	2.5
N_b	4
K_{rCO2}^{max}	0.7
K_{rb}^{max}	1.00
$S_{b\text{-}irr}$	0.15

2.3.7.3 Hysteresis Modeling

Hysteresis refers to a phenomenon where relative permeability curves differ depending on whether the fluid displacement occurs during drainage or imbibition. In drainage, the non-wetting phase (CO_2) displaces the wetting phase (brine), while in imbibition, the reverse occurs. Carlson's hysteresis model is used for the imbibition curve and is applied only to the non-wetting phase (CO_2). It provides a robust framework for accurately simulating multiphase flow in reservoirs, with a strong focus on the effects of saturation history and fluid trapping, making Carlson's hysteresis model highly relevant for CO_2 sequestration.

The plots in Figure 2-17 illustrate the relative permeability curves used for the mid-case model. The plot on the left is the brine drainage curve vs. water saturation, and at right the plot displays the drainage and imbibition curves for CO_2, with gas saturation on the x-axis. The green CO_2 drainage curve is scaled for a critical gas saturation of 5%. The critical gas saturation is the saturation at which a fluid is capable of flowing throughout the pore space. Saturations below 5% render the CO_2 immobile.

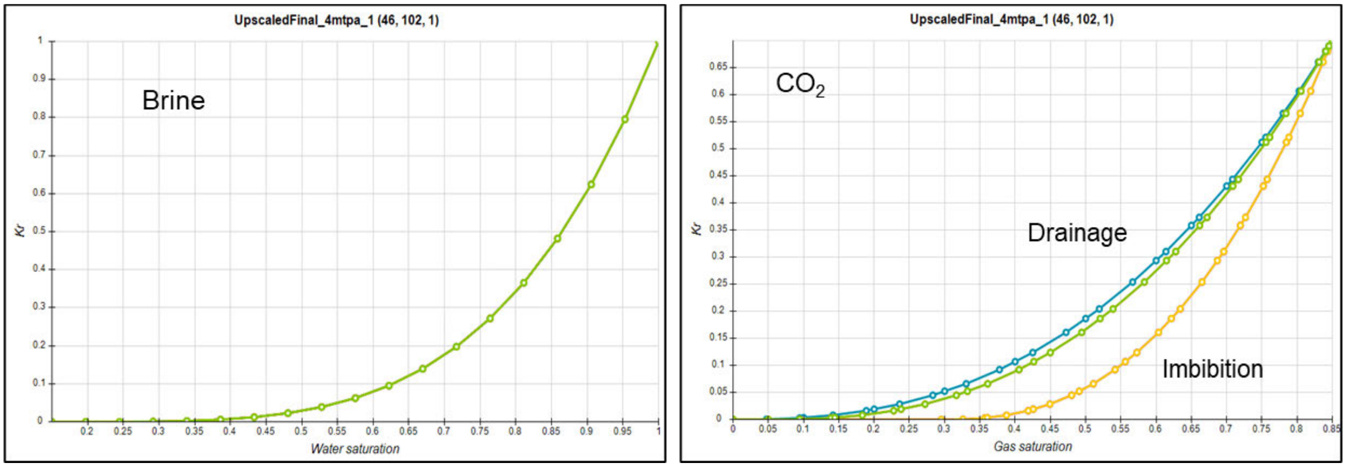


Figure 2-17 – Model Relative Permeability Curves

2.3.7.4 Residual Gas Saturation

The range of maximum residual gas saturation (S_{grm}) is extensive and can vary from 0.1 to 0.9, based on published literature. The S_{grm} increases with an increase in clay content in sandstones and decreases with an increase in sorting and grain size. A relationship has been established between porosity and S_{grm} (Figure 2-19):

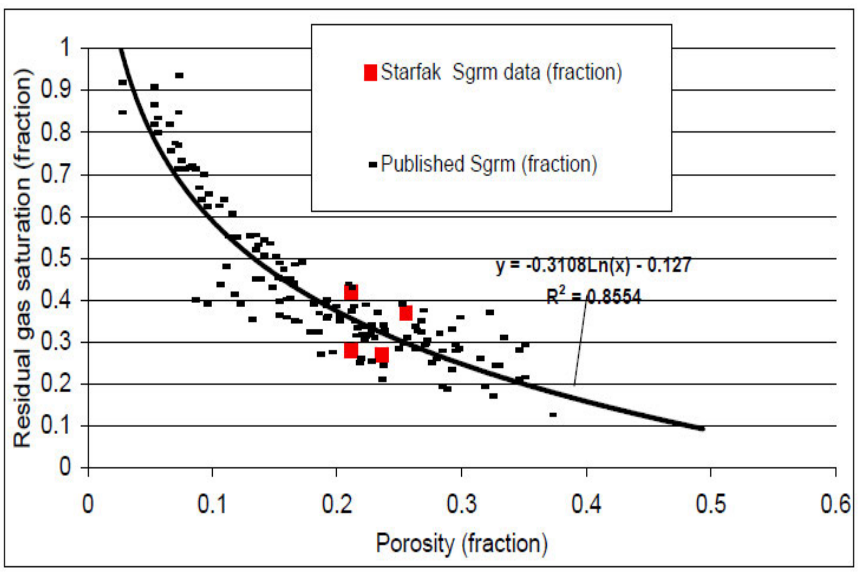


Figure 2-18 – Reservoir characterization applying residual gas saturation modeling (example from Starfak T1 Reservoir, Middle Miocene Gulf of Mexico).

This relationship for residual gas is derived from a paper on the Starfak T1 Reservoir (Holtz, 2005) and is applied in the simulation model. The relationship as shown in the previous plot (Figure 2-18) was applied to every grid cell. The resultant grid is used as the residual gas end point (S_{gt}) for imbibition curves, and S_{gt} will vary for each grid block based on its porosity. Values are clipped at 40% (Figure 2-19).

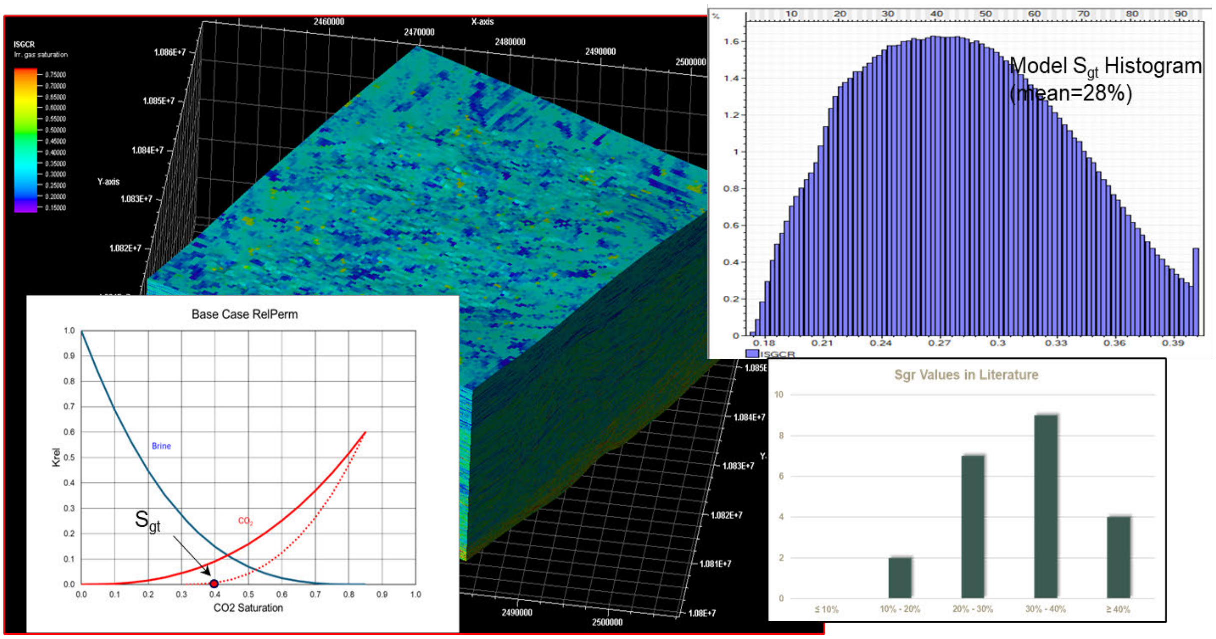


Figure 2-19 – Summary of Modeled Residual Gas Saturation

The mean model residual gas value is 28%, this and the complete range are consistent with values found in the Starfak reservoir paper.

2.3.7.5 Capillary Pressure Curves

Capillary pressures are used to better represent the behavior at the water/CO_2 contact. As the fluid saturations change over time, the pressure needed to displace fluids changes following the capillary pressure curve. Capillary pressures are modeled using Brooks-Corey parameters. In the absence of core capillary pressure experiments, a Louisiana Miocene mercury injection capillary pressure (MICP) sample from Iberia Parish, Louisiana, is used as an analogue. Results are compared with additional analogue capillary-pressure curves from a deltaic environment with similar petrophysical properties. The red curve displayed in Figure 2-20 is the input used in the simulation model.

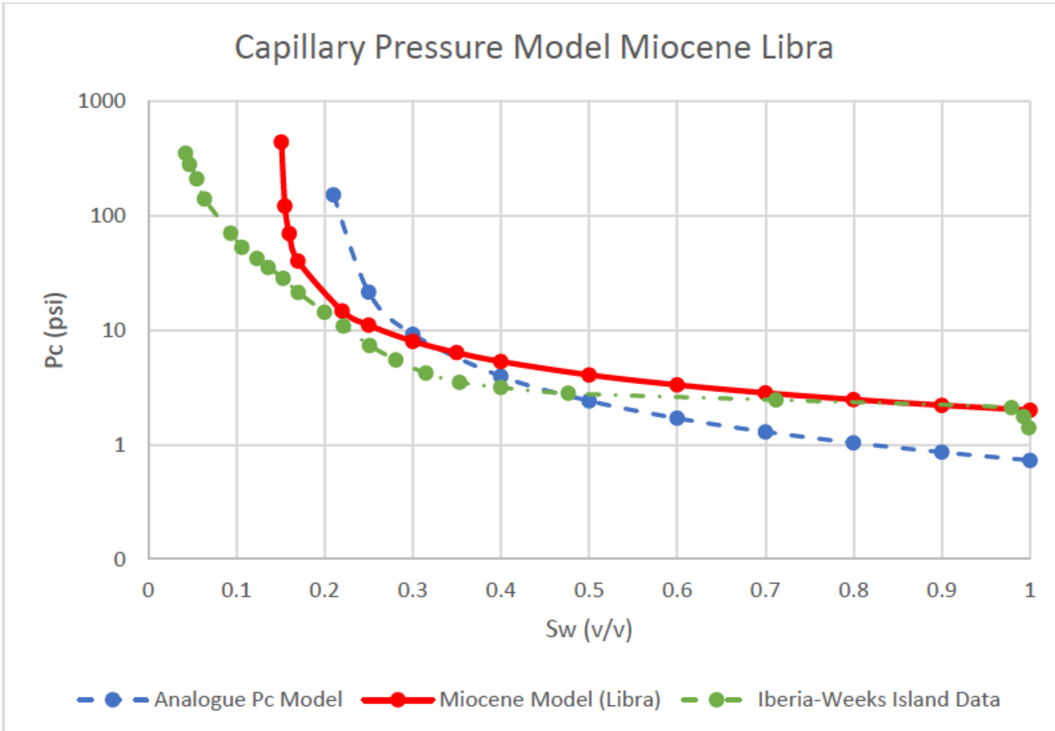


Figure 2-20 – Capillary Pressure Curve

Inputs to the capillary pressure equation are summarized in Figure 2-21 to generate the model capillary pressure table also shown in the figure:

$$p_c = \frac{c_w}{\left(\frac{S_w - S_{wR}}{1 - S_{wR}}\right)^{a_w}}$$

Cw (psi) Capillary Entry Pressure	2
Sw (v/v) @ Pc=0	0.15
aw Shape Factor	0.8
Max Pc (psi)	500

Pc	Sw	Sg
psi	v/v	v/v
441.1	0.151	0.849
121.7	0.155	0.845
69.9	0.160	0.840
40.2	0.170	0.830
14.7	0.220	0.780
11.1	0.250	0.750
8.0	0.300	0.700
6.4	0.350	0.650
5.3	0.400	0.600
4.1	0.500	0.500
3.3	0.600	0.400
2.8	0.700	0.300
2.5	0.800	0.200
2.2	0.900	0.100
2.0	1.000	0.000

Figure 2-21 – Capillary Pressure Equation and Results

2.3.8 Field Management Strategy

The Field Management Strategy sets the dynamic aspect of reservoir simulation and defines the strategy used to develop a project. Wells, their locations, rates, operational controls, and constraints are specified in the strategy to cover the entire simulation period. Determining the most appropriate scenario for the future of the project is a matter of testing many different strategies, and the selected scenario is discussed further below.

2.3.8.1 <u>Well Locations</u>

Well locations are chosen to best optimize the development plan. The primary drivers for location selection were to minimize the critical pressure front and constrain the plume area to the lease area, avoid legacy wells as much as possible, maintain the desired rates and volumes, and keep well BHPs below 90% fracture pressure. Multiple locations were evaluated, and the ultimate well locations are selected based on the aforementioned criteria. Figure 2-22 is a top structure map of the Middle Miocene zone, showing the well pad as a blue dot. All three proposed injectors are located on this well pad.

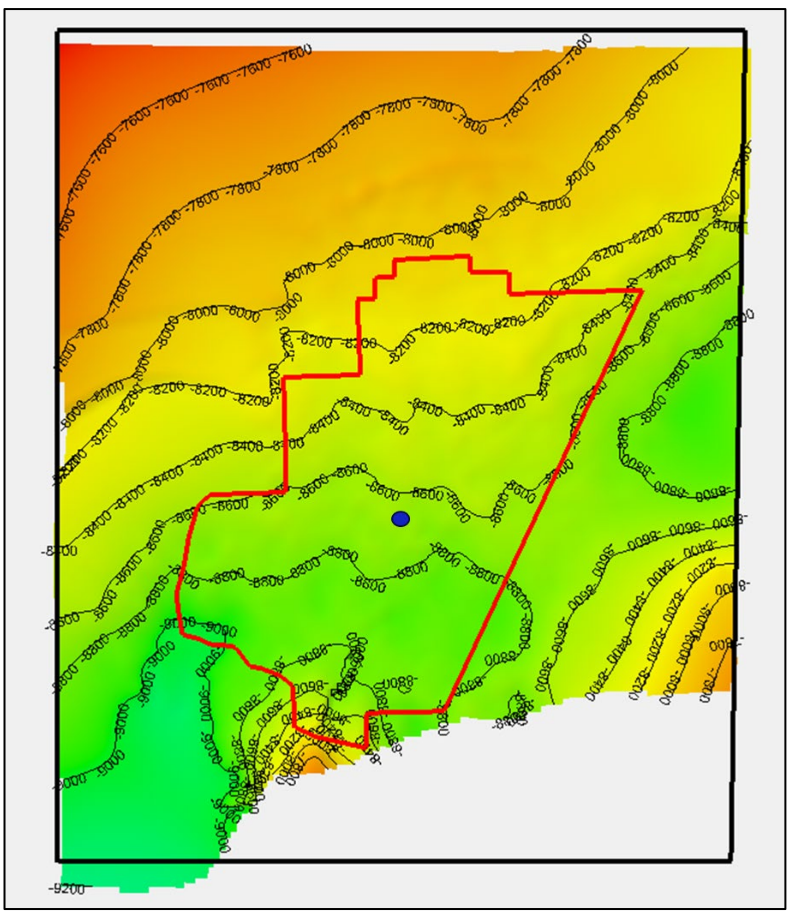


Figure 2-22 – Structure Map of Middle Miocene With Property Outline and Well Pad Location (blue dot)

Table 2-9 summarizes the three well locations showing the model coordinates using the model coordinate system.

Table 2-9 – Injection Well Locations

WGS_1984_BLM_Zone_15N_ftUS				
	MODEL Surface Location			
Well	X (ft)	Y (ft)	Longitude (X)	Latitude (Y)
Simoneaux CCS Injector Well No. 001	2473868.3	10828822.0	90° 22' 17.2194" W	29° 48' 35.3154" N
Simoneaux CCS Injector Well No. 002	2473843.2	10828822.0	90° 22' 17.508" W	29° 48' 35.3154" N
Simoneaux CCS Injector Well No. 003	2473818.2	10828822.0	90° 22' 17.796" W	29° 48' 35.3154" N

2.3.8.2 Injection Strategy

The development plan includes three proposed injection wells located on the same pad and near each other. Each well will inject across approximately one-third of the gross interval. Additionally, each well has two completions for a total of 20 years of injection. None of these wells inject into the same intervals at any given time. The injection duration is 8–10 years per completion, depending on the injection well start date. The wells will be drilled 1 year apart, reaching a combined project plateau injection rate of 4 million metric tons per annum (MMTPA) when Simoneaux CCS Injector Well No. 003 is brought online. The first completion of each well injects for 10 years and is then recompleted into the next, shallower injection zone, which is active until Year 20—after which, all wells are shut in.

Figure 2-23 displays all three injectors' completions, zones, and model permeability on the four different tracks. Injection occurs in the deepest intervals first, followed by recompletion 10 years later. Zones 01_Top_Grid through 09__3010 are excluded at this time, but may be considered in the future.

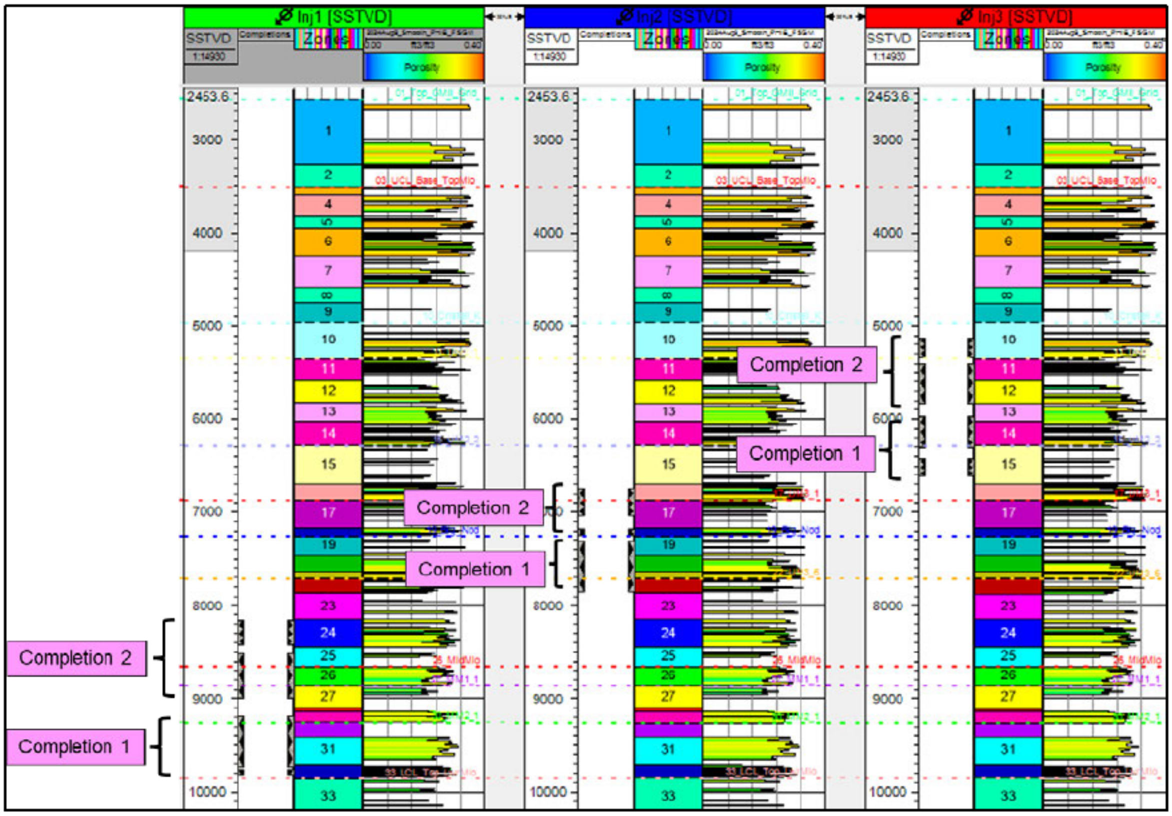


Figure 2-23 – Injector well tracks with permeability showing completion zones.

Table 2-10 summarizes the completion interval depths, injection dates, and total number of injection years per completion. Actual completion interval depths might vary slightly from the depths listed in the table below, pending final site-specific well results. Start and end dates for injection might vary slightly too, pending the start date of the project. The total project injection duration, however, will not exceed 20 years.

Table 2-10 – Injection Well Completion Plan

Well	Completion Interval	Zones Perfed	Top Perf	Bottom Perf	Inj Start Date	Inj End Date	Inj Years
Simoneaux CCS Injector Well No. 001	1	Zone 29-32	9187	9734	Jan-27	Jan-37	10
Simoneaux CCS Injector Well No. 001	1	Zone 32	9757	9824	Jan-27	Jan-37	10
Simoneaux CCS Injector Well No. 001	2	Zones 25-27	8513	8990	Jan-37	Jan-47	10
Simoneaux CCS Injector Well No. 001	2	Zone 24	8168	8429	Jan-37	Jan-47	10
Simoneaux CCS Injector Well No. 002	1	Zones 19-22	7306	7860	Jan-28	Jan-38	10
Simoneaux CCS Injector Well No. 002	2	Zone 18	7181	7245	Jan-38	Jan-47	9
Simoneaux CCS Injector Well No. 002	2	Zone 17	6924	7052	Jan-38	Jan-47	9
Simoneaux CCS Injector Well No. 002	2	Zones 16-17	6838	6896	Jan-38	Jan-47	9
Simoneaux CCS Injector Well No. 003	1	Zone 15	6424	6608	Jan-29	Jan-39	10
Simoneaux CCS Injector Well No. 003	1	Zones 14-15	6201	6308	Jan-29	Jan-39	10

Well	Completion Interval	Zones Perfed	Top Perf	Bottom Perf	Inj Start Date	Inj End Date	Inj Years
Simoneaux CCS Injector Well No. 003	1	Zones 13-14	5959	6145	Jan-29	Jan-39	10
Simoneaux CCS Injector Well No. 003	2	Zones 11-12	5403	5817	Jan-39	Jan-47	8
Simoneaux CCS Injector Well No. 003	2	Zone 10	5129	5334	Jan-39	Jan-47	8

2.3.8.3 Wellbore Hydraulics Parameters

All wells are modeled as vertical. Wellbore models are built in Petrel using the Well Engineering module and are simple in nature—with the casing perforated at the injection intervals. Wellbore radius at the injection intervals is 0.3125 ft. Completion skin values are assumed to be zero. Vertical lift curves are not currently included in the simulation model. However, the flowing BHPs for each injector were provided for flow assurance analysis, and Table 2-11 contains the estimates for wellhead pressure (WHP) and temperature based on rate and BHP. More details regarding well operations and hydraulics and be found in *Section 4 – Well Construction*.

Table 2-11 – Injection Well WHP Summary

Injection Year	Pump Discharge Temperature (°F)	Simoneaux CCS Injector Well No. 001 Wellhead Pressure (psia)	Simoneaux CCS Injector Well No. 001 Wellhead Temperature (°F)	Simoneaux CCS Injector Well No. 002 Wellhead Pressure (psia)	Simoneaux CCS Injector Well No. 002 Wellhead Temperature (°F)	Simoneaux CCS Injector Well No. 003 Wellhead Pressure (psia)	Simoneaux CCS Injector Well No. 003 Wellhead Temperature (°F)
2027	50	1752	50.0				
	85	2520	85.0				
	122	2928	115.5				
2028	50	1715	49.9	1699	49.9		
	85	2490	84.9	2213	82.0		
2029	50	1693	49.9	1679	49.8	778	45.2
	85	2472	84.8	2194	81.8	1374	70.5
	122	2931	119.0	2599	114.3	1694	96.7
2037	50	1881	49.9	1599	48.9	819	45.0
	85	2532	84.8	2121	80.5	1260	68.1
2038	50	1829	49.9	1680	49.4	816	45.1
	85	2489	84.8	2288	82.7	1260	68.4
2039	50	1802	49.9	1602	49.2	798	45.0
	85	2467	84.8	2219	82.1	1292	69.1
	122	2902	119.0	2612	114.9	1590	94.2

*psia – pounds per square inch absolute

2.4 Model Results

Model results yielded a cumulative CO_2 injection of 76.5 million metric tons (MMT) from the three proposed injectors after 20 years, as described above. At the end of simulation (200 years), 47%, 36%, and 17% of the injected CO_2 is trapped as residual, mobile, and dissolved CO_2, respectively. The results are discussed in more detail in the following sections.

2.4.1 Field Injection Results

Field-level simulation results are presented in Figure 2-24. A field injection rate of 4 MMTPA is attained with Simoneaux CCS Injector Well No. 003 at the beginning of Year 3 of injection and maintained until Year 20. Reservoir pressure increases with injection and eventually stabilizes following injection shut-in. The cumulative CO_2 injected for the entire project life is, as noted above, 76.5 MMT.

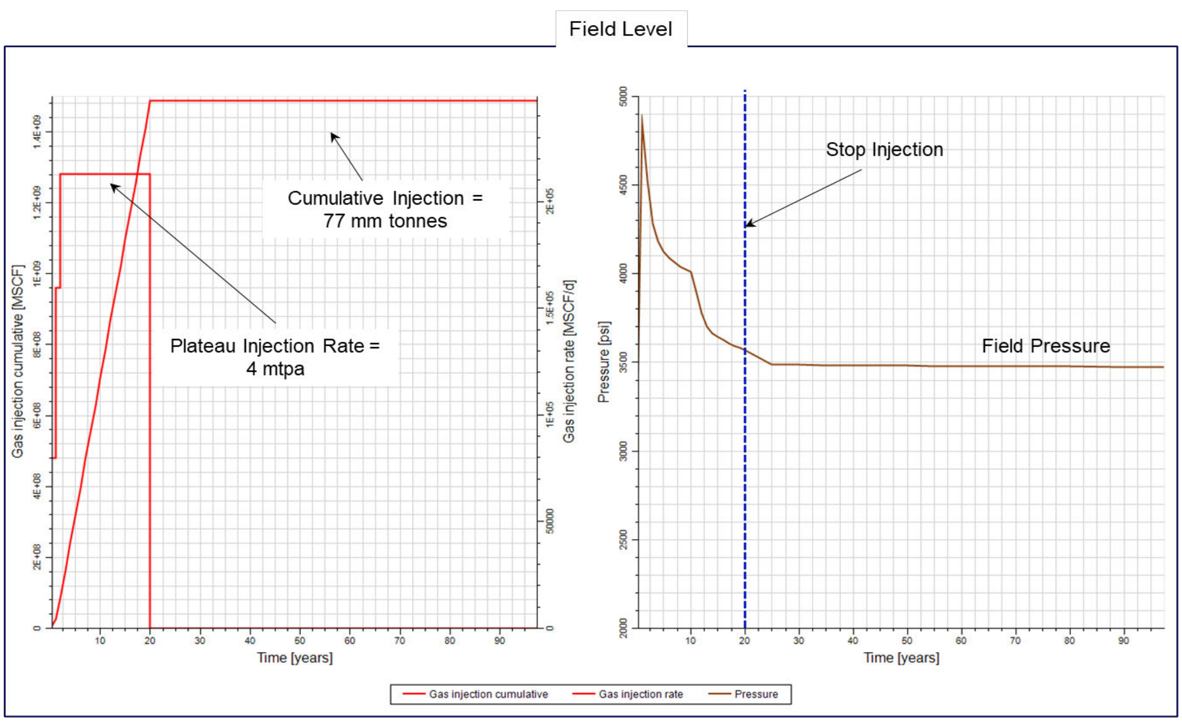


Figure 2-24 – Field Pressure and Injection Rate for the Libra project

2.4.2 Well Injection Results

Target injection rates for Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 are 1.5, 1.5, and 1.0 MMTPA, respectively. Applied well constraints are the gas injection rate and BHPs. The BHP constraints are set at 90% of the fracture pressure. Figures 2-25 through 2-27 show the performance of each well, and plotted on each graph is injection rate, BHP constraint (green line), BHP (black line), and cumulative gas injection. The completions can sustain the assigned rates throughout the injection periods. The cumulative CO_2 injection into Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 is 30, 28.5, and 18 MMT, respectively.

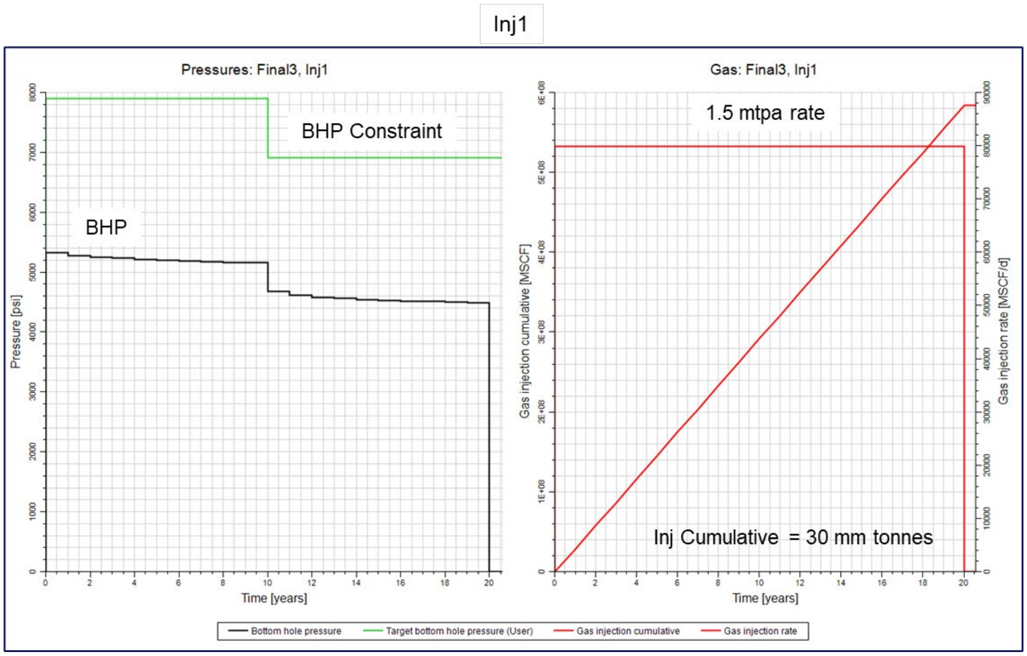


Figure 2-25 – Modeled BHP and Injection Rate for Simoneaux CCS Injector Well No. 001

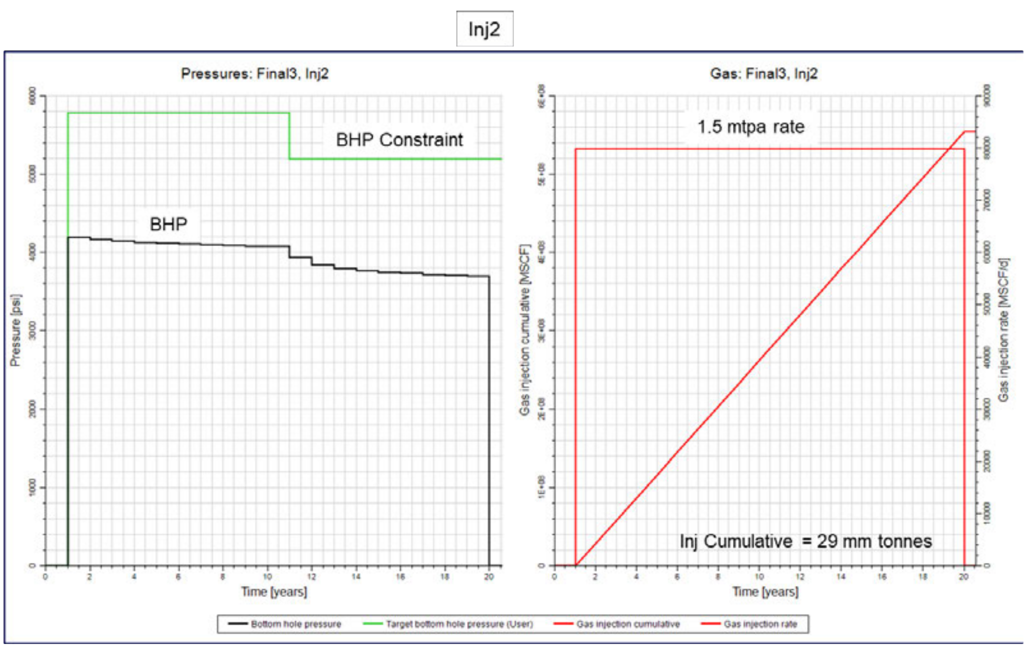


Figure 2-26 – Modeled BHP and Injection Rate for Simoneaux CCS Injector Well No. 002

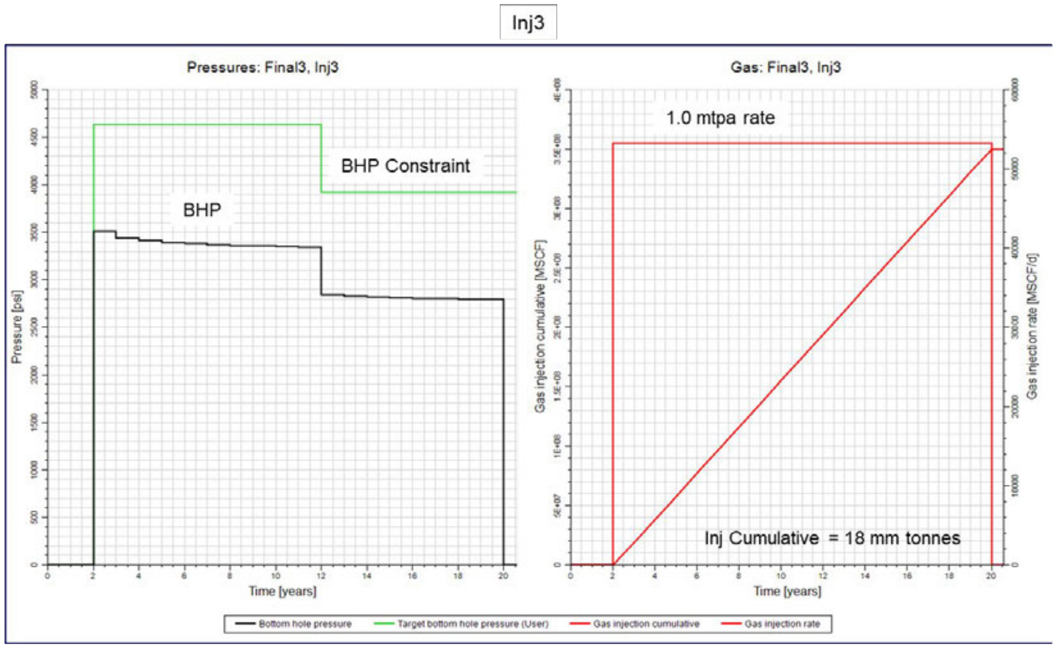


Figure 2-27 – Modeled BHP and Injection Rate for Simoneaux CCS Injector Well No. 003

2.4.3 Trapping Summary

The CO_2 trapping mechanisms refer to the ways in which CO_2 can be captured and stored, preventing its release into the atmosphere and mitigating climate change. These mechanisms are broadly categorized into four types: mobile, residual, dissolved, and mineral.

When CO_2 is initially injected, it remains in a mobile state until it is trapped through physical or chemical processes, reducing its mobility over time. This is the primary mechanism during the active injection period, declining with time following injection termination.

The CO_2 trapped in geological formations that remain immobile is called residual trapping. After CO_2 is injected, some of it becomes trapped in the tiny pores of the rock through capillary forces. This happens as the CO_2 migrates through the porous formation, leaving small amounts behind in pore spaces, which become disconnected from the larger flow and are immobilized.

The CO_2 can dissolve into saline formation water within the rock formation. Initially, CO_2 dissolves quickly into the aquifer, stabilizing over time as the water becomes saturated. Once dissolved, the CO_2 cannot migrate as a separate phase, making it less likely to escape to the surface.

Mineral trapping is a long-term mechanism where dissolved CO_2 reacts chemically with the minerals in the host rock to form stable carbonate minerals. This process locks CO_2 in solid mineral form, ensuring that it cannot escape. Because this trapping mechanism is the slowest of all trapping mechanisms, occurring over long periods of time, often ranging from hundreds to thousands of years, geochemical reactions are not included in the model but will be reevaluated when site-specific data is available.

Figure 2-28 displays the three different trapping mechanisms from the model results. The red line is the mobile, the green is the residual, and the blue line is dissolved CO_2 through time up until the end of simulation (200 years). The cumulative CO_2 injection at the end of the 20-year injection period is 1.73e11 pound mass (lbm). At the end of simulation, 47%, 36%, and 17% of the injected CO_2 is trapped as residual, mobile, and dissolved CO_2, respectively. These mechanisms will continue to change with time, following the trends established by this plot.

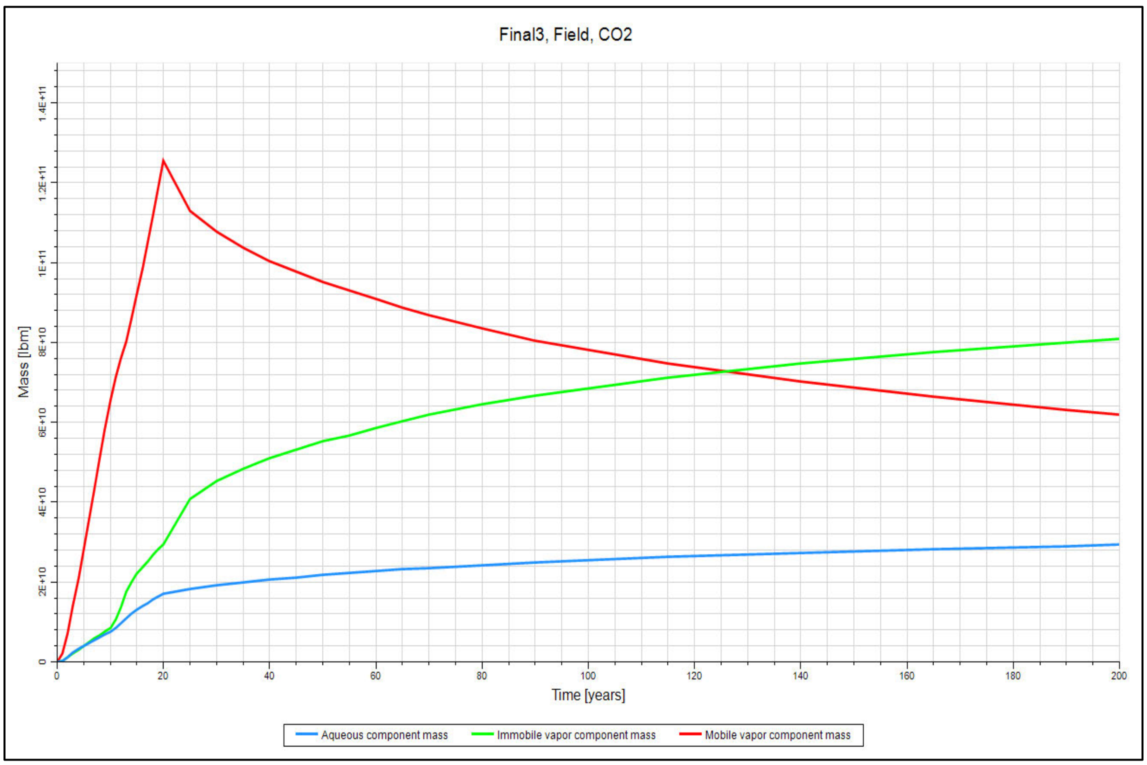


Figure 2-28 – Trapping Mechanism Volumes Over Time

2.4.4 Critical Pressure Front for Area of Review Delineation

Geological characterization data and dynamic modeling results are used to define the AOR. Results delineate the projected area and vertical migration of the CO_2 plumes for each interval, as well as the associated critical pressure fronts, pressure front decline, and plume stabilization post-closure.

The AOR is the region where the operator of Class VI injection wells must identify all penetrations that can potentially breach the confining and/or injection zones, allowing fluids to migrate into Underground Sources of Drinking Water (USDW). The penetrations within the AOR must have been properly plugged to prevent fluid movement and be remediated if necessary. The AOR boundary is the maximum extent of both the CO_2 plumes and the critical pressure front over the life of the Libra project.

2.4.4.1 Critical Pressure Front Determination

The critical pressure front represents the area where the pressure due to injection can cause fluids to migrate into USDWs via existing or hypothetical conduits. The methodology used to calculate the pressure front for the Libra project was developed by E.I. du Pont de Nemours & Co. . It has been verified and used by multiple Class I applications in the Gulf Coast to evaluate pressure fronts for at least 30 years. The fundamental assumption of this method is that the only potential pathway for fluid movement between the injection interval and USDWs is through artificial penetrations like active or inactive wells—in the absence of naturally occurring, vertically transmissive conduits like faults or fractures. Pressure increase in the injection interval must exceed the threshold pressure (critical pressure) required to displace the mud within the wellbore and overcome the minimum gel strength.

A static mud column generates hydrostatic pressure. For an abandoned well to facilitate fluid movement, the combined pressures from injection (Pi) and the original formation pressure (Pf) must exceed the pressure of the static mud column (Ps). Additionally, the gel strength pressure (Pg) of the mud in a static fluid column must be considered. Therefore, for fluid to move upward, the sum of the original formation pressure and injection pressure must be greater than the static fluid column pressure plus the mud's gel strength pressure. This relationship, show in Equations 5 through 7, is based on a simple balance of forces (Davis, 1986):

(Eq. 5)

$$Pf + Pi > Ps + Pg$$

Where:
Pf = original formation pressure (pounds per square inch gauge (psig))
Pi = formation pressure increase due to injection (psi)
Ps = static fluid column pressure (psig)
Pg = gel strength pressure (psi)

(Eq. 6)

$$Ps = 0.052 * h * M$$

Where:
h = depth to the injection reservoir from the 50 ft fallback
M = fluid weight (pounds per gallon (lb/gal))

0.052 = conversion factor so that Ps is in psi

(Eq. 7)

$$Pg = \frac{(0.00333 * G * h)}{d}$$

Where:
G = gel strength (pounds per 100 square feet (lb/100 ft^2))
d = borehole diameter (inches (in.))
0.00333 = conversion factor for Pg expressed in psi

A gel strength of 20 lb/100 ft^2 was used. Field evidence of the longevity of mud as a plugging material has been demonstrated during well reentries. The Nora Schulze No. 2, located in Nueces County, Texas, was reentered by Envirocorp in the late 1980s. The well was plugged and abandoned with 10.6–11.0 lb/gal mud when abandoned in 1959 . Mud samples were taken upon reentry to a depth of approximately 754 ft using tubing pushed into the mud column, starting from a depth of 120 ft. Below a depth of 754 ft, the mud could only be displaced from the well by breaking circulation (i.e., the tubing string could not be advanced) . The average mud weight of the recovered samples was 11.1 lb/gal, showing that the mud did not appreciably change over the intervening 29 years following original abandonment. The gel strengths of the samples ranged between 217 lb/100 ft^2 to greater than 320 lb/100 ft^2. These values are over an order of magnitude greater than the 20 lb/100 ft^2 value commonly used for abandoned well assessment purposes. In addition, shear strengths of the mud samples ranged from 170 lb/100 ft^2 to 7,000 lb/100 ft^2, increasing with depth.

For the gel-strength pressure calculation, all well bores were considered open hole, which is a conservative approximation. For cased holes, the parameter “d” would equal the effective annular diameter (borehole diameter minus the outside casing diameter), which is significantly smaller, resulting in a higher calculated gel-strength pressure.

The conservative 50-ft fallback is an extra safety factor, assuming the entire wellbore will not be filled with mud.

Nearby wells were examined to determine mud weights and wellbore diameters for wells in the project area, and this data was used for the above calculations. ~~in the absence of site-specific data~~. The lowest mud weight from Table 2-12 (9.3 pounds per gallon (ppg)) and wellbore diameter of 10 in. were used for the Libra project critical pressure front calculations.

Table 2-12 – Plugged Well Data Summary for Critical Pressure Calculations

Well No.	Mud Weight (ppg)	Wellbore Diameter (in.)	Depth (ft)	Source/Note
55235	10.5	12.250	10,452	Log Header
75831	10.7	12.250	10,506	Log Header
236901	11.0	9.875	11,300	Log Header
237039	-	9.875	11,610	No Data – LLOX PAD
237172	-	9.875	11,910	No Data – LLOX PAD
166990	11.0	9.875	10,314	Log Header
186913	-	12.250	11,506	No Data – Same Pad as 186005
186005	9.3	12.250	9,795	Log Header
168952	10.9	9.875	11,281	Log Header
108246	12.1	9.875	12,025	Log Header – OH to 2,700 ft
79525	11.1	8.500	11,000	Log Header
125786	12.0	9.875	12,500	Log Header
151705	11.8	9.875	12,140	Log Header – OH to 2,500 ft

*OH – Open hole

These equations were input into the Petrel calculator to generate a critical pressure threshold grid, and a post-processing workflow was created to facilitate these calculations. The resultant critical pressure threshold grid is pictured in Figure 2-29. Threshold pressures vary with depth and range from 25 psi to 272 psi from top to bottom of the grid.

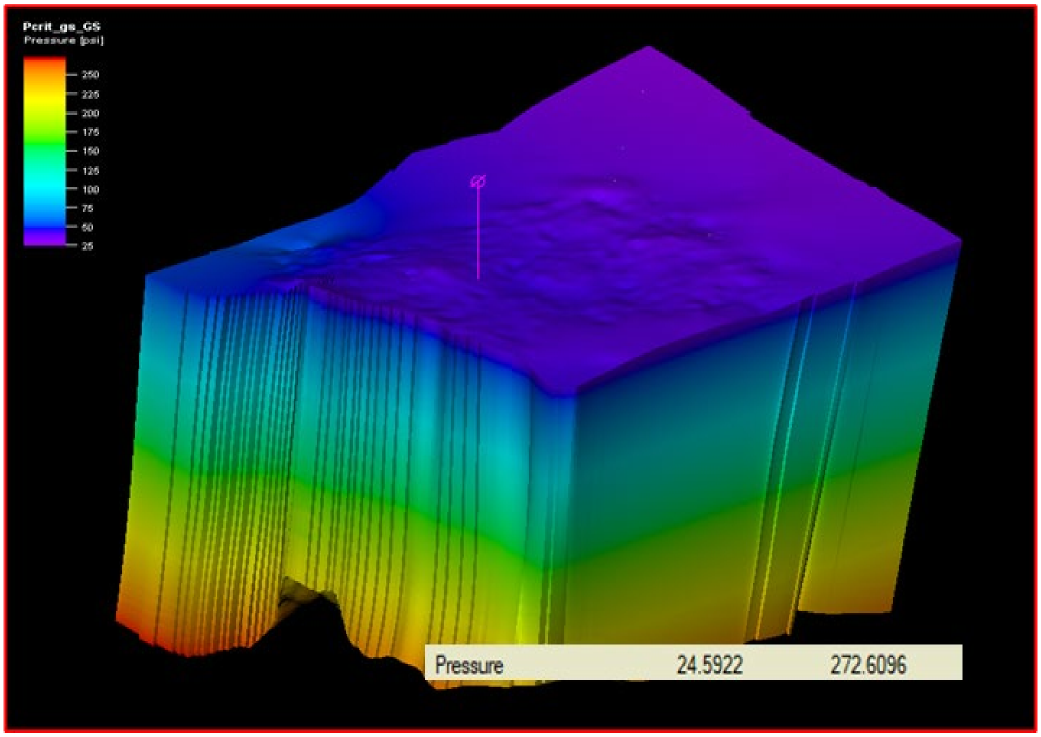


Figure 2-29 – Model Critical Pressure Thresholds

After the simulation model has been run, pressures at selected time steps are converted to a 3D grid property. A delta pressure (deltaP) property is then calculated and converted to another 3D grid property. The deltaP grid is next compared to the critical pressure threshold grid to identify those grid blocks exceeding the threshold, and if deltaP exceeds the threshold pressure in a grid block, the grid block is flagged, creating another 3D grid property called PcFlag. Lastly, the workflow takes the PcFlag grid, filters out blocks less than the pressure threshold, then generates polygons of critical pressure areas for selected time steps.

The critical pressure fronts at various points in time, as well as the final amalgamated critical pressure front, are shown in Figure 2-30. Also shown are legacy wells (blue dots) and the lease outline in red.

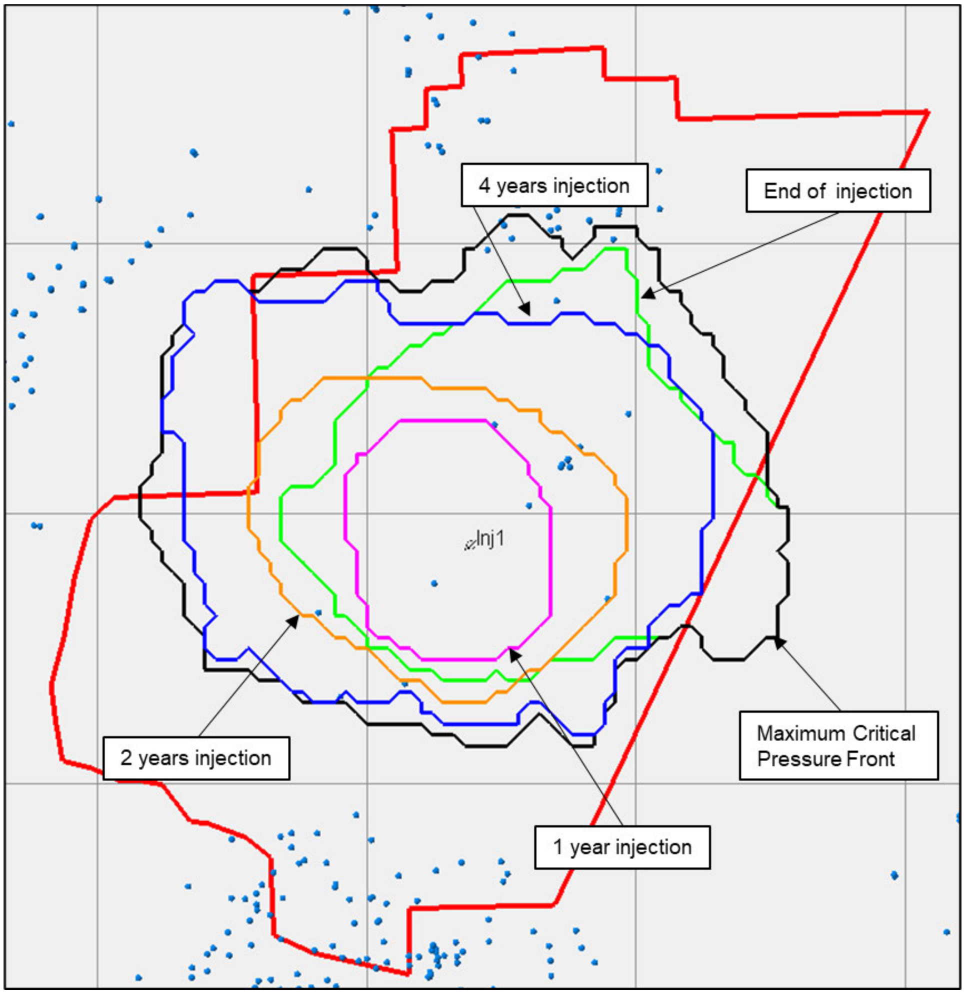


Figure 2-30 – Multi-Year Critical Pressure Front Comparison

The critical pressure front dissipates once injection ceases after 20 years.

2.4.5 CO_2 Plume Migration for AOR Delineation

Migration of the CO_2 plume is the movement of injected CO_2 within the subsurface during and following injection. During injection, the CO_2 displaces brine, creating a high-pressure zone around the injection wells. This pressure drives the CO_2 outwards, forming a plume. Buoyancy effects cause the CO_2 plume to rise toward the top of the reservoir, and dissolution into the brine occurs even during the injection phase, slightly reducing the volume of the free CO_2 plume. Once injection stops, the reservoir pressure gradually decreases, reducing the driving force behind the CO_2 movement, and will continue to rise toward the top of the reservoir until it encounters impermeable layers.

The Libra project's dynamic model is an essential tool in the prediction of plume movement through time. The model allows the complex interactions between CO_2, brine, and the geologic characteristics. Figures 2-31 and 2-32 illustrate the 2D plume outline and 3D gas saturation—

where greater than 3%—with views of the plumes at the end of injection and 50 years post-injection, respectively. The plumes are stacked from injection into different zones from the three injectors located very near each other.

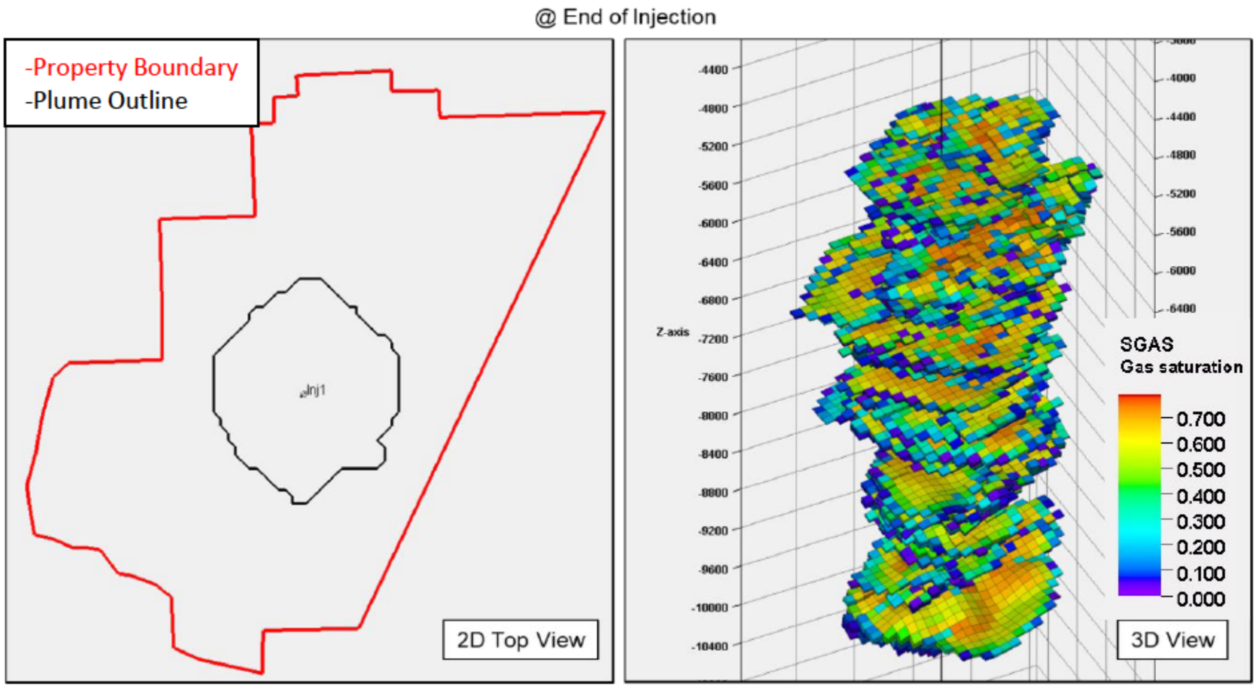


Figure 2-31 – Plume Extent at the End of Injection

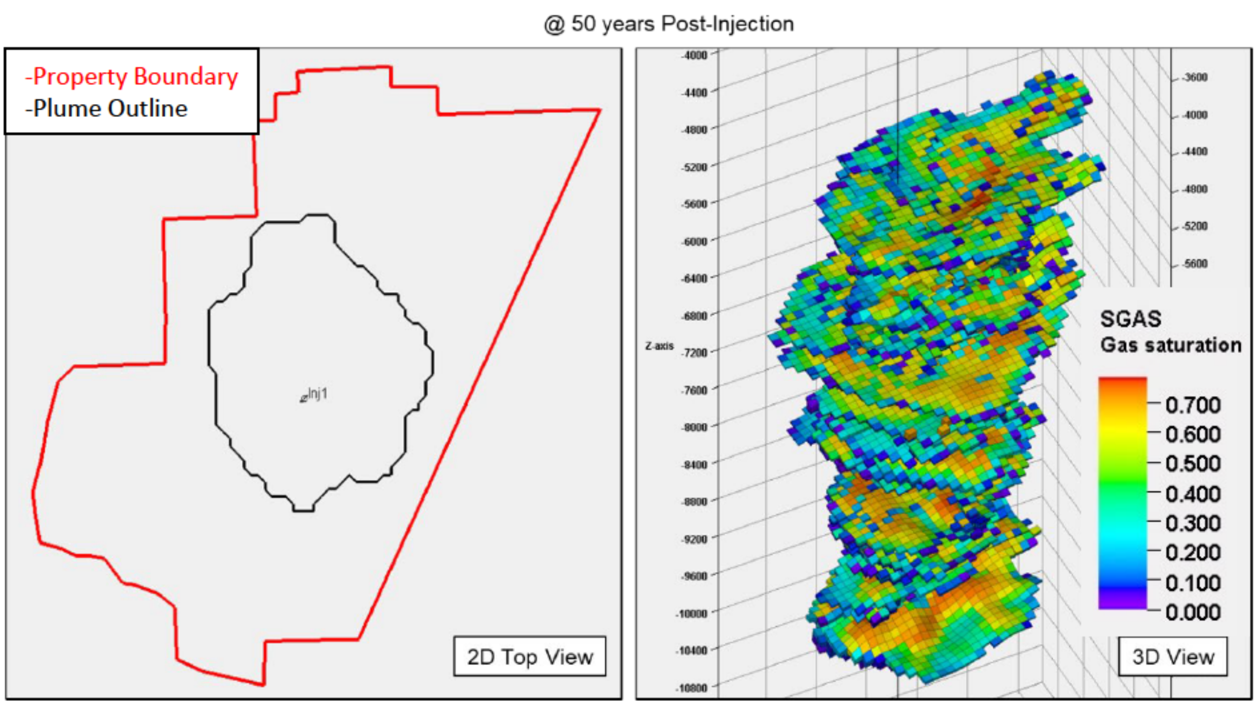


Figure 2-32 – Plume Extent at 50 Years Post-Injection

A north-south I-slice (I = 59) of gas saturation from the model in the injection intervals at the end of simulation (200 years) is presented in Figure 2-33.

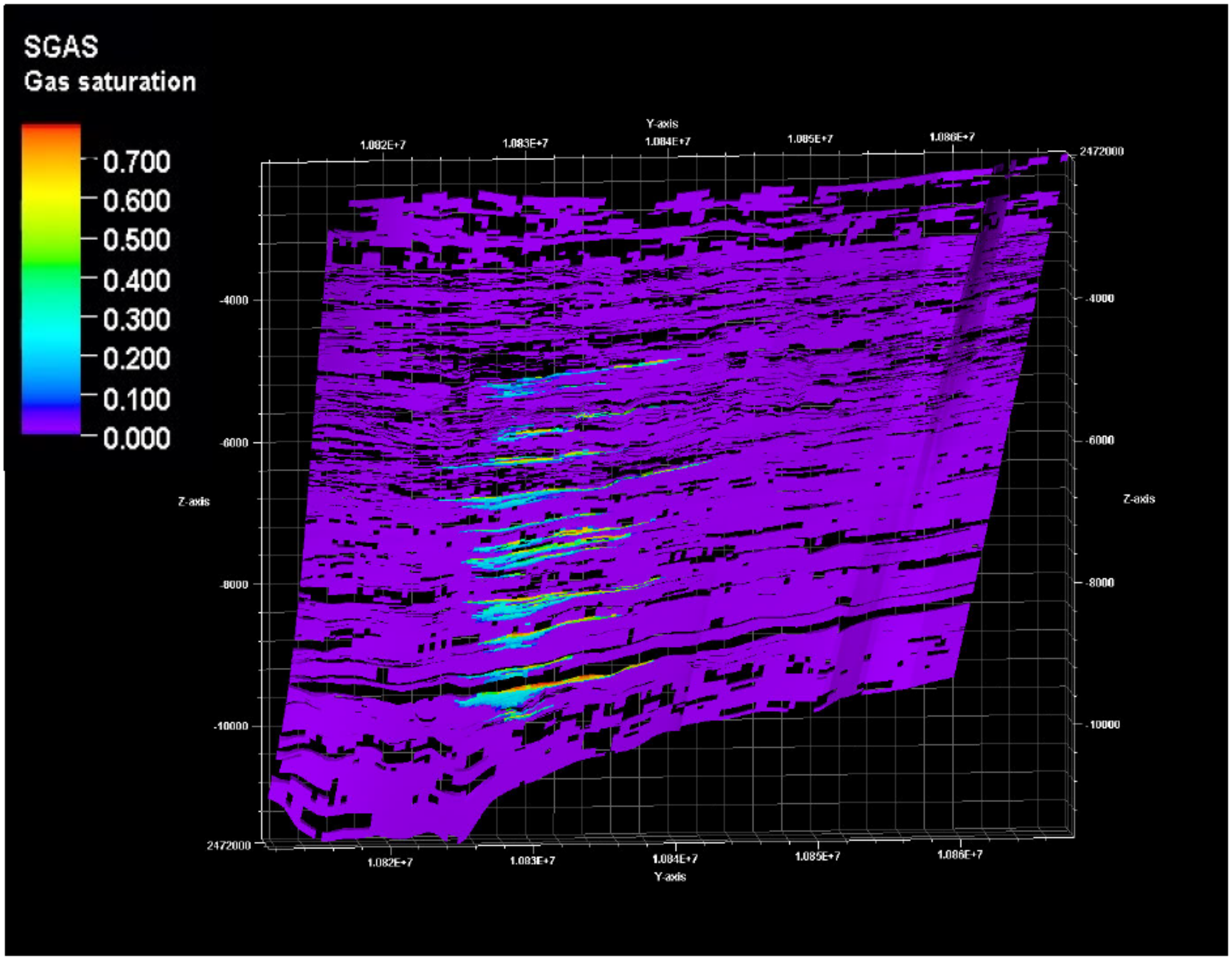


Figure 2-33 – North-South Cross Section of the Plume Extent at End of Simulation

2.4.6 Stabilized Plume Growth Analysis

Figure 2-34 illustrates the areal plume growth through time from injection start to 50 years post-injection shut-in (SI). The polygons represent composite plumes from all injection intervals where gas saturation is greater than 3%.

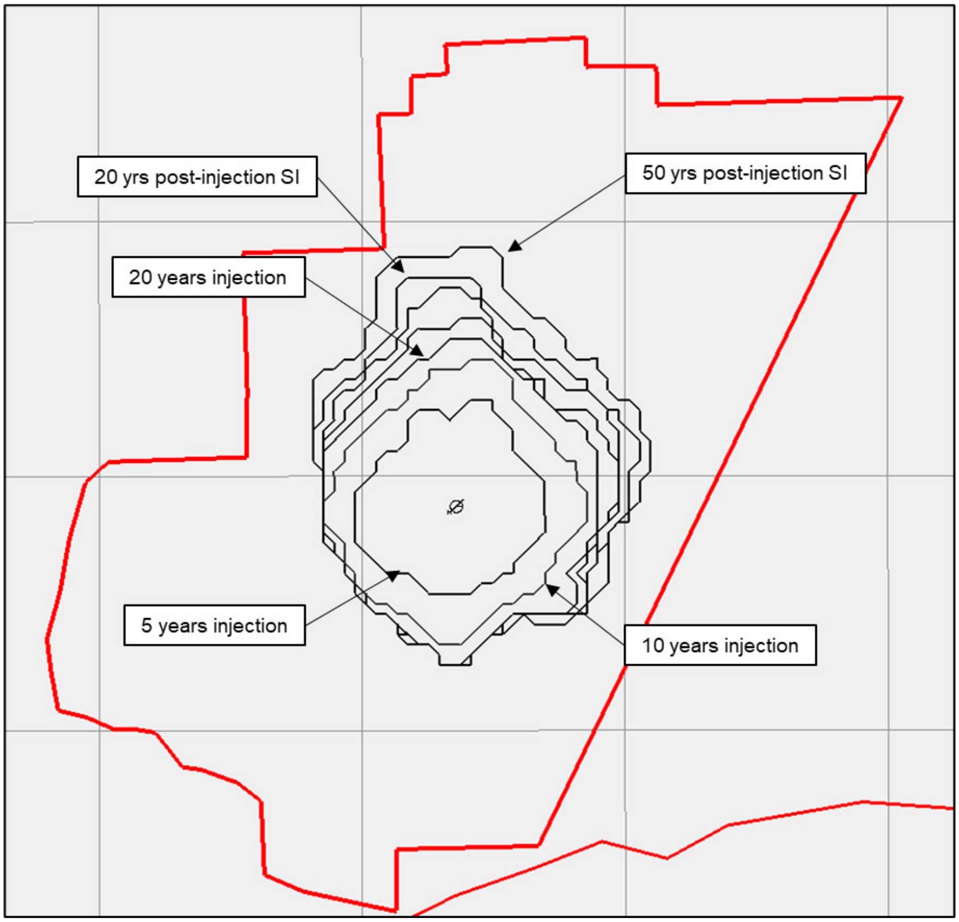


Figure 2-34 – Multi-Year Comparison of Aerial Plume Extents

Polygon areas are calculated for post-injection plumes to calculate plume growth following injection cessation. The graph in Figure 2-35 shows the plume growth after the end of injection. Monthly time steps are plotted for the first 5 years, then yearly time steps for Years 5 to 70 and every 5 years after that. Smaller time steps were taken for the initial period to adequately capture the initial decline in plume growth. A power trend was fitted through the points (dark blue dotted line). This shows that the plume stabilizes around 40–50 years post-injection, at a negligible residual 0.5% plume growth. In the graph, a black, manually fitted trend line was also included—showing a similar behavior. Based on these simulation results, Lapis proposes a 50-year post-injection site care (PISC) time frame. During injection, as part of the regular 5-year AOR reevaluations, the PISC time frame will also be reevaluated based on actual monitoring data and adjusted up or down accordingly, following approval from the Louisiana Department of Energy and Natural Resources (LDENR).

Even though the plume appears to have stabilized after 50 years, the ratios between the various trapping mechanisms continue to change (Figure 2-28).

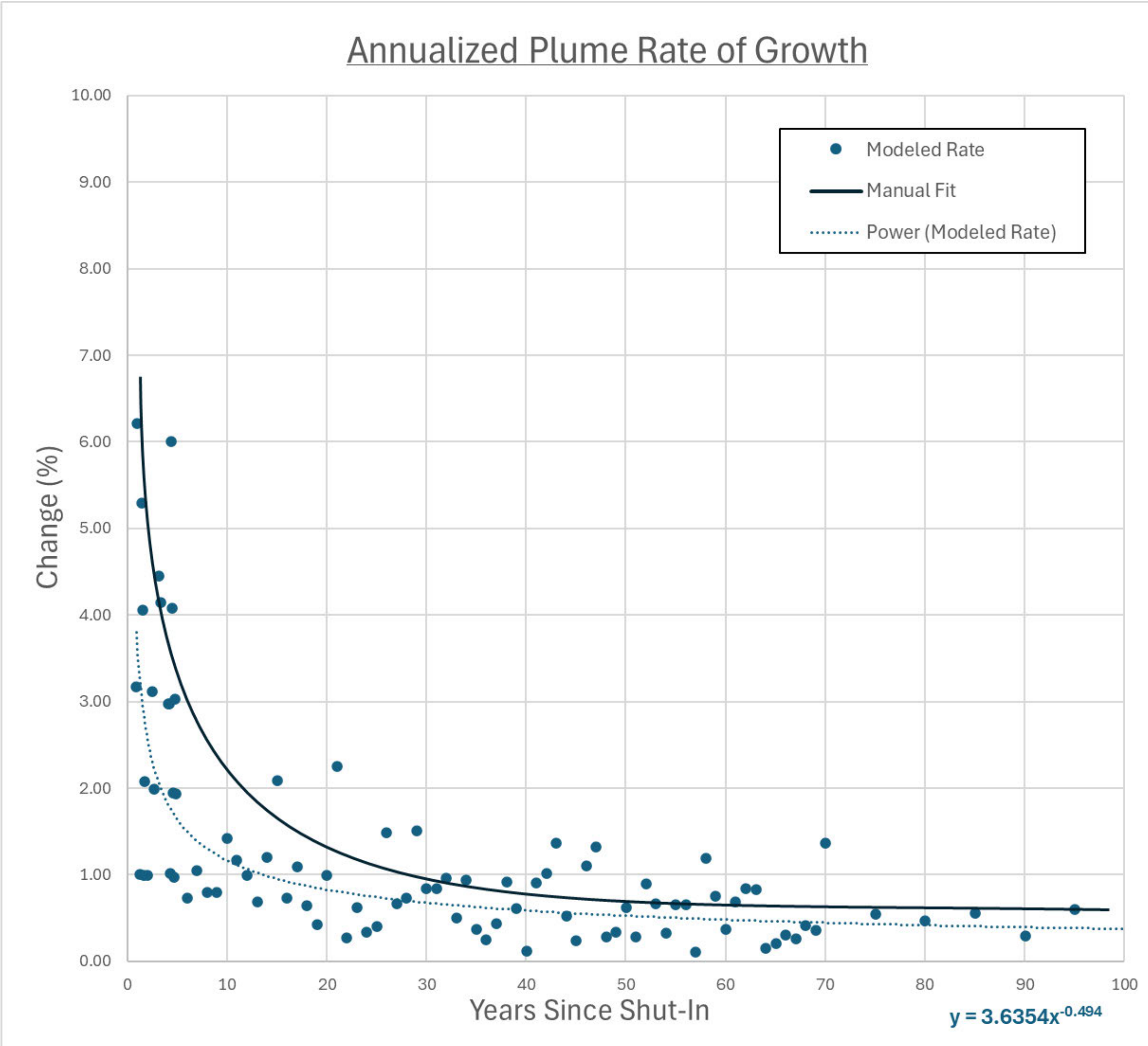


Figure 2-35 – Annualized Plume Rate of Growth

2.5 Offset Injection Analysis

A search for offset injection wells located within a 1-mi radius of the Libra project acreage was conducted to evaluate the impact of injection from these wells on the project. Six offset saltwater disposal (SWD) injection wells are located within the 1-mi radius, displayed in Figure 2-36.

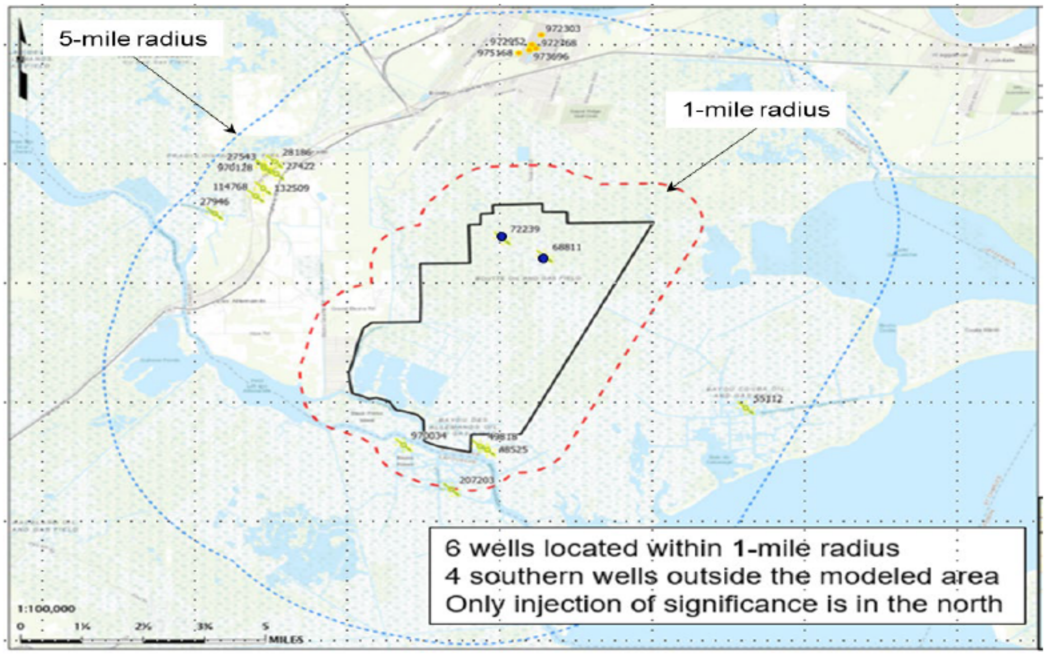


Figure 2-36 – Map of Offset SWD Injectors

Of the six wells within the 1-mi radius, only two have injection volumes of any significance that might impact the project area. Table 2-13 details information for the six offset SWD wells, including completion intervals, report dates, and reported total volumes through the end of 2023.

Table 2-13 – Summary of Offset SWD Injection Operations

		Injection Interval				
Well Serial Number	**API Number**	**From**	**To**	**First Reported Injection Start Date**	**Last Reported Date**	**Reported Total Injected Volume (million bbls)**
970034	1705788162	1,190	1,276	Jan-13	Jan-24	5.8
48525	1708900229	1,750	2,820	Jan-13	Jan-24	5.5
49818	1708900183	1,980	2,170	Jan-13	Jan-24	0.1
72239	1708900213	2,650	5,230	Jan-14	Jan-24	5.9
207203	1705722407	2,727	2,747	Jan-13	Jan-24	0.0
68811	1708900217	6,590	6,610	Jan-22	Jan-24	1.0

The four wells in the south are outside the model grid. However, the two northern wells, SN 68811 and 72239, are located within the modeled area. These two wells are perforated as illustrated in Figure 2-37. The SN 72239 well is perforated in Zones 01_Top_Grid through 11, most of which is above the Libra project injection interval, except for Zones 10 and 11_UM2_1.

The SN 68811 well is perforated at the base of Zone 16_UM2_Base, which is within the project injection interval.

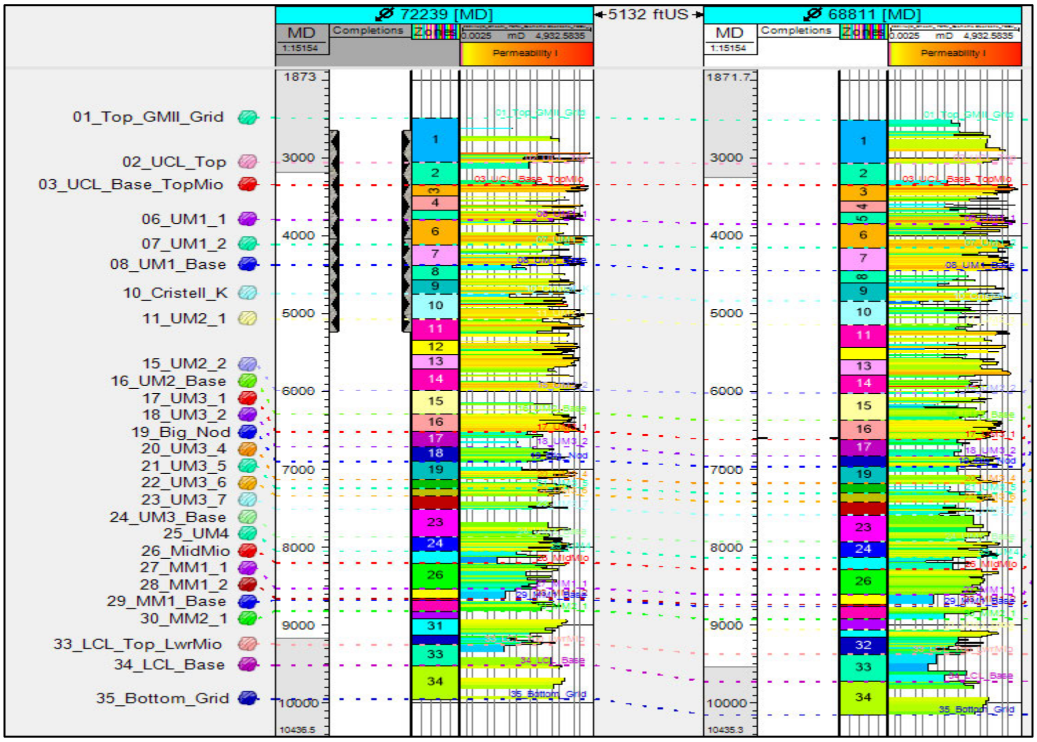


Figure 2-37 – Well profiles for offset injectors with model zones for reference.

Injection rates and volumes for these injection wells are displayed in Figure 2-38 and Figure 2-39. These historical volumes were included in the simulation run, along with the CO_2 injection wells, to evaluate the impact of these water injection wells on the Libra project. Since no additional injection volumes are available for these wells beyond year-end 2023, future water-injection rates are set at the last reported rates, and water injection continues through the CO_2 injection 20-year period.

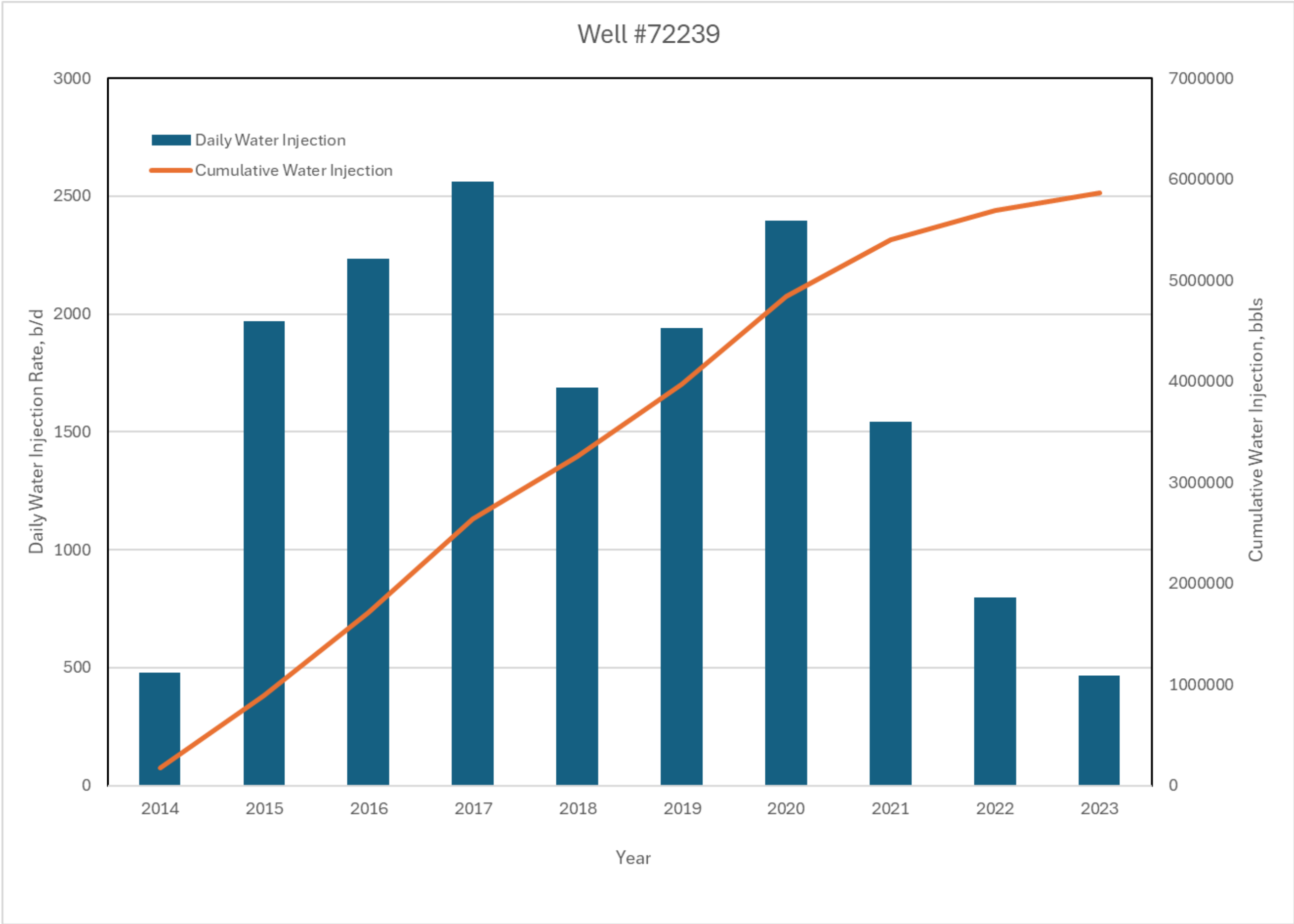


Figure 2-38 – Offset Well #72239 Injection Rate and Cumulative Water Injection

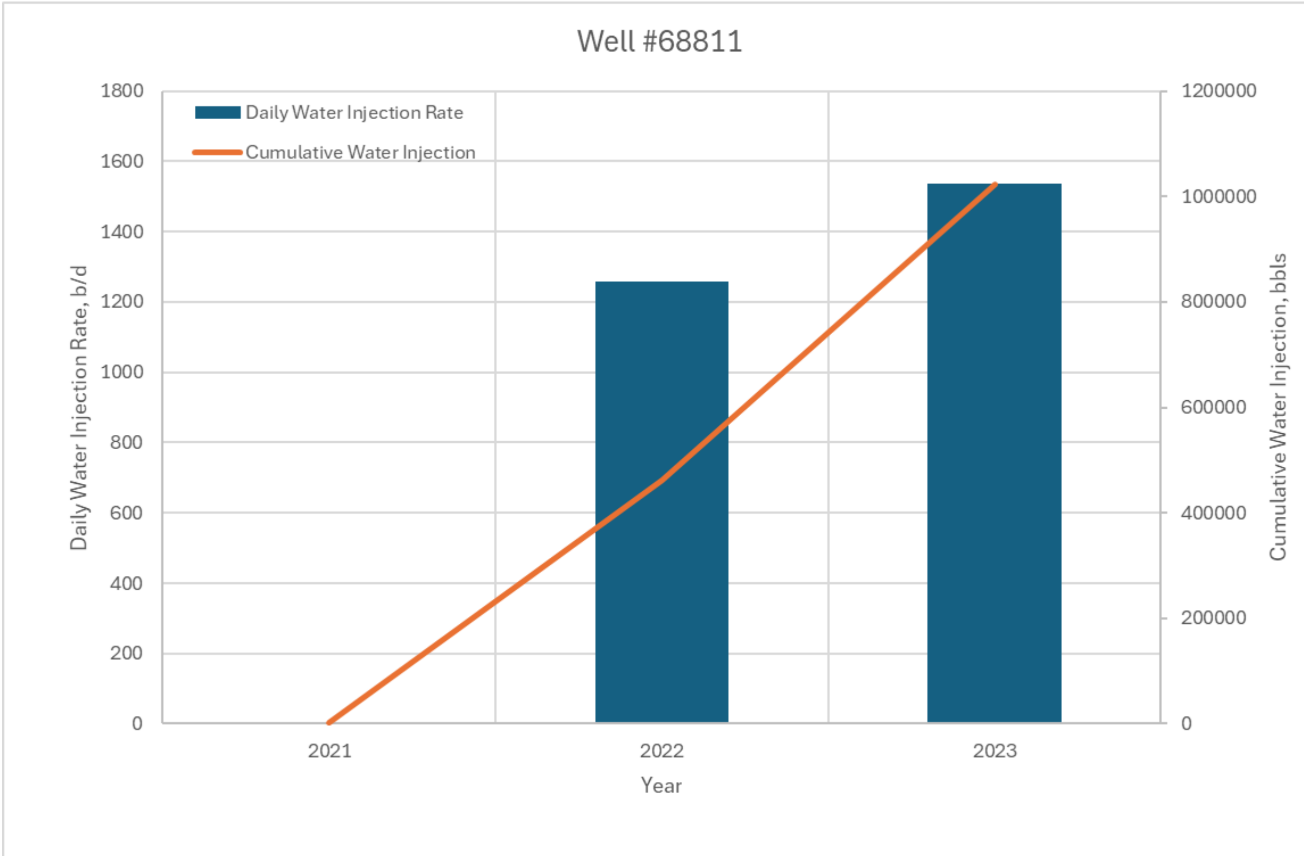


Figure 2-39 – Offset Well #68811 Injection Rate and Cumulative Water Injection

Results indicate that there is little to no impact on the performance of the project area due to the water injection wells. Most of the perforated interval in the SN 72239 well lies above the project's target injection interval, except for Zones 10 and 11, and injection into the SN 68811 is minimal prior to the start of CO_2. Cumulative water injection at the end of the 20-year CO_2 injection period is 22.6 million barrels (bbls). No difference was observed in the plume or critical pressure front when compared to runs without water injection.

2.6 Uncertainty Analysis

Full uncertainty analyses have not been performed to date but will be done when additional site-specific data is available. In the interim, however, sensitivities to specific parameters and their impact on the plume and critical pressure fronts were conducted for the current model as well as in previous model versions.

2.7 Final AOR

Adhering to SWO 29-N-6 **§3615.A** [40 CFR **§146.84**], the AOR is determined by the maximum extent of either the CO_2 plume or critical pressure front—or both. Figure 2-40 illustrates the final AOR at 50-years post-injection. This final AOR map is included in *Appendix C* as item *C-1 Oil and Gas Wells AOR Map*. More information about the final AOR and legacy wells is provided in *Section 3 – Area of Review and Corrective Action Plan*.

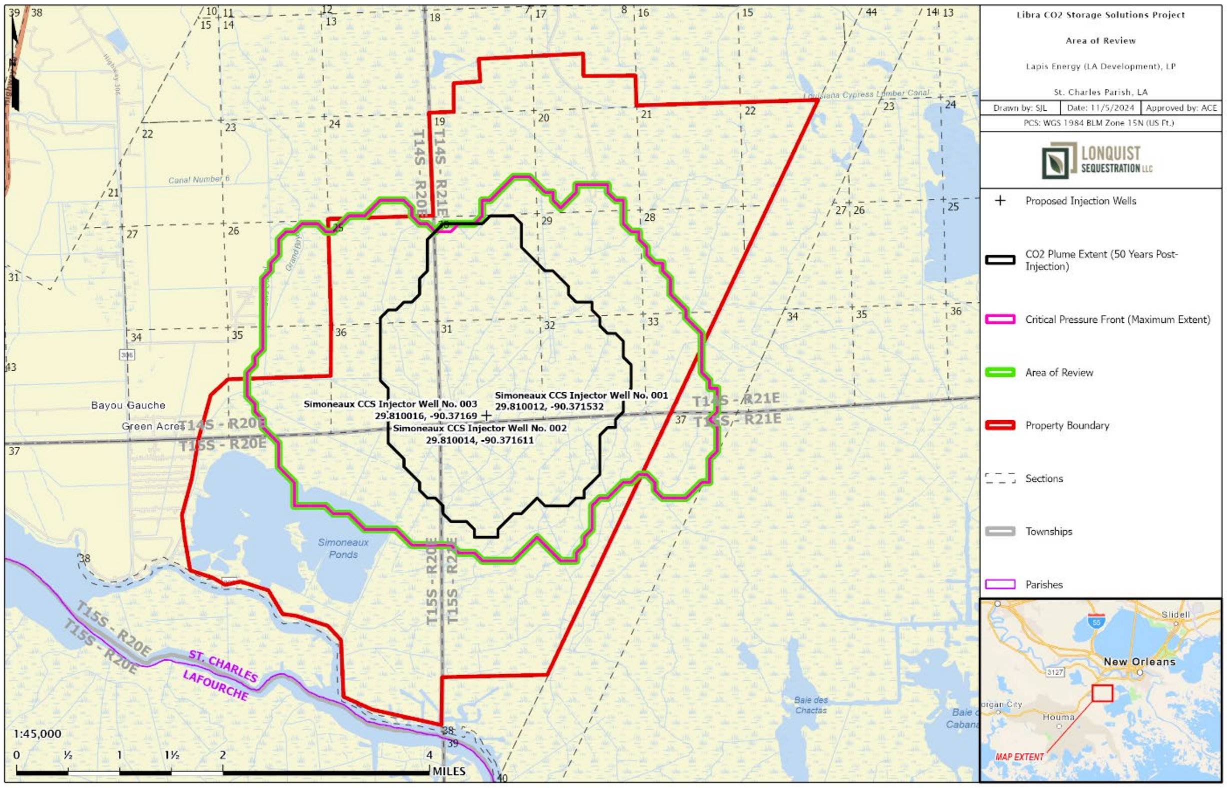


Figure 2-40 – Libra project Final AOR

2.8 References

2.8.1 Rock Compressibility

Yale, D.P., Nabor, G.W., Russell, J.A. et al. (1993). Application of variable formation compressibility for improved reservoir analysis. Presented at the SPE Annual Technical Conference and Exhibition, Houston, TX, October 3-6, 1993. SPE 26647.

2.8.2 Pressure and Temperature

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2.8.3 Fracture Gradient

Althaus, V. E. (1977). A New Model for Fracture Gradient. *The Journal of Canadian Petroleum*, 98-108

Eaton, B. A. (1969). Fracture Gradient Prediction and Its Application in Oilfield Operations. *SPE-AIME*, 1353-1360. https://onepetro.org/JPT/article/21/10/1353/164490/Fracture-Gradient-Prediction-and-Its-Application (accessed 2023)

Nelson, P. (2012). "Overpressure and Hydrocarbon Accumulations in Tertiary Strata, Gulf Coast of Louisiana." USGS.

2.8.4 Relative Permeability

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Holtz, M. (2005). "Reservoir Characterization Applying Residual Gas Saturation Modeling, Example from the Starfak T1 Reservoir, Middle Miocene Gulf of Mexico".

2.8.5 Critical Pressure Front Determination

Davis, K.E. (1986). Factors affecting the area of review for hazardous waste disposal wells. Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Association, Dublin, Ohio, 148-194.

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

TABLE OF CONTENTS

Figures

Tables

3.1 Facility Information

Project Name: Libra CO_2 Storage Solutions Project

Project -Contact: Brandon Anderson, Libra Project Manager
Lapis Energy (LA Development), LP
5420 LBJ Fwy, Bldg. 2
Suite 1330
Dallas, Texas 75240
469-629-1766 / permitting@lapisenergy.com

Well Locations: St. Charles Parish

Simoneaux CCS Injector Well No. 001
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.315" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.226" W

Simoneaux CCS Injector Well No. 002
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.317" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.510" W

Simoneaux CCS Injector Well No. 003
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.319" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.793" W

*CCS – carbon capture and sequestration
Geologic coordinate system (GCS) –
NAD 27 – North American Datum of 1927

3.2 Computational Modeling

Model Name: Schlumberger Intersect™ Simulation Software (Ver. 2023.4)

Model Authors/Institution: Lapis Energy (LA Development), LP

Description of Model: Equation of state (EOS) reservoir simulator, designed for modeling compositional CO_2 injection into saline aquifers

Model Inputs and Assumptions: The parameters for the Libra CO_2 Storage Solutions Project (Libra) project model are summarized in Table 3-1.

Table 3-1 – Model Input Parameters and Assumptions

Input	Value
Per-Well Injection Rate (MT/yr)	1 – 1.5 MMTPA
Average Effective Porosity (%)	16.3
Average Permeability (mD)	175
Temperature Gradient (°F/100 ft)	1.4
Fracture Gradient (psi/ft)	0.67 – 0.85
Brine Salinity (ppm)	125,000
Injected Fluid Composition	100% CO_2

*MT/yr – metric tons per year
MMTPA – million metric tons per annum
mD – millidarcy
psi/ft – pounds per square inch per foot
ppm – parts per million
°F – degree Fahrenheit

3.3 Area of Review Discussion

Statewide Order (SWO) 29-N-6, **§3615.B** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an area of review (AOR) investigation be conducted for a Class VI carbon sequestration well application. The EPA defines the AOR as the greater of either (1) the maximum extent of the separate-phase plume (pore occupancy (CO_2) plume) or (2) the pressure front—where the pressure buildup is of sufficient magnitude (i.e., pressure front plume) to force fluids from the injection zone into the formation matrix of an Underground Source of Drinking Water (USDW). The Libra project AOR was determined using a combination of both definitions.

3.3.1 Area of Review: Pore Occupancy Plume

The pore occupancy plume was determined through reservoir simulation that accounts for the physical and chemical properties of every phase of injected CO_2 and its interaction with the in situ brine. The assumptions and data used for construction of this model originated from site characterization, operational records, and literature. A comprehensive overview of the modeling effort to establish the extent of the pore occupancy plume is presented in *Section 2 – Plume Model*.

The AOR for the pore occupancy plume was investigated to identify and assess artificial penetrations, subsurface features, and pore space rights.

The artificial penetrations (e.g., wellbores) located within the AOR have been assessed to ensure proper completion, plugging, and construction using appropriate materials. Class VI regulations require these wellbores to be constructed or plugged using materials capable of facilitating the long-term storage of carbon oxides and protection of the USDW. Any wellbore found within this AOR that penetrated the gross injection zone was evaluated to determine its effect on the integrity of the containment of CO_2. Wellbores that were deemed to be insufficiently constructed or plugged are included in the Corrective Action Plan in *Section 3.4*.

The AOR is also evaluated for subsurface features, to determine their influence or lack thereof on the primary injection zone. These features can include faults, mapped fractures, folds, steeply dipping formations, and salt diapirs, among others. These features may assist in the confinement of CO_2, by acting as impermeable barriers to flow. They may also, however, facilitate fluid movement out of the injection zone. It has been established that any such identified feature should not be allowed to facilitate the escape of CO_2 to the surface.

The results of the reservoir modeling simulation show that the CO_2 plume extent will remain on the acreage owned by Lapis Energy (LA Development), LP (Lapis) for the entirety of the Libra project. The plume portion of the AOR boundary was observed based on when the plume growth was determined to be “stable.” Plume stability was established to be the time at which the plume rate of growth reaches 0.5% per year. The annualized plume rate of growth is depicted in Figure 3-1. Monthly time steps are plotted for the first 5 years; yearly time steps for Years 5 to 70—and every 5 years after that. Smaller time steps were taken for the initial period to adequately capture the initial decline in plume growth. A power trend was fitted through the points (indicated by the dark blue dotted line). This shows that the plume stabilizes around 40–50 years post-injection, at a negligible residual 0.5% plume growth. A black manually fitted trend line was also included showing a similar behavior.

Based on these simulation results, Lapis proposes a 50-year post-injection site care (PISC) time frame. During injection—as part of the regular 5-year AOR reevaluations—the PISC time frame will also be reevaluated based on actual monitoring data and adjusted up or down accordingly, following approval from the Louisiana Department of Energy and Natural Resources (LDENR).

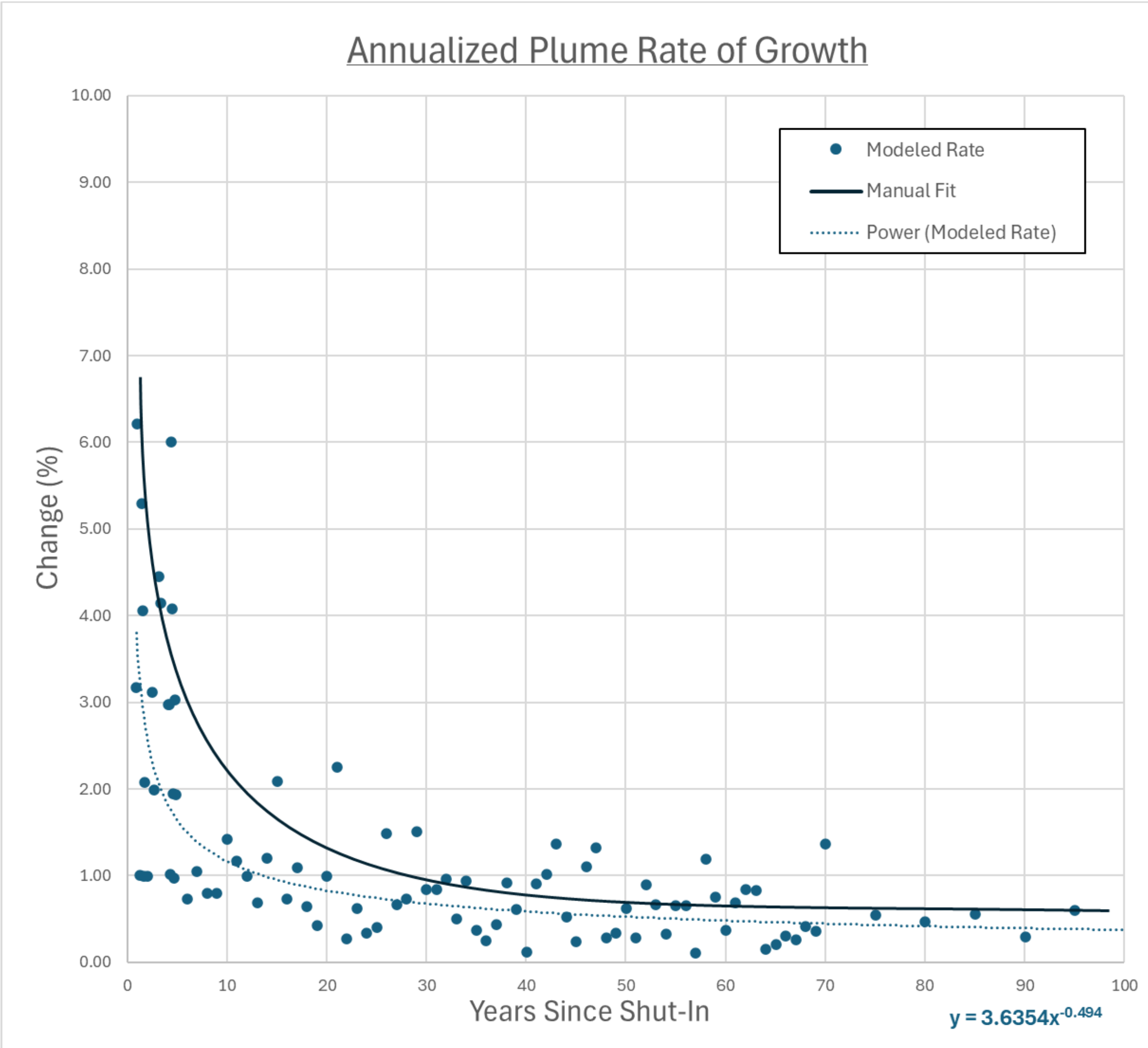


Figure 3-1 – Annualized Plume Growth

3.3.2 Area of Review: Pressure Front

The other portion of the AOR to be reviewed is the pressure front created during the injection of fluids into a previously stable reservoir. The pressure front plume AOR is determined through calculation and simulation. The AOR defines the pressure buildup value, in pounds per square inch (psi), that could potentially result in fluid migration out of the designated injection interval. This is calculated for inadequately plugged and abandoned artificial penetrations or subsurface features that extend into the upper confining zone (UCZ).

A wellbore that is open or insufficiently plugged and abandoned—and open to both the top of the injection interval and the base of the USDW—has the ability to facilitate fluid migration up into the USDW. The *critical pressure* is the pressure (psi) at which this migration can occur.

The base of the USDW is is estimated to be found at approximately 1,222 feet (ft) from the Kelly bushing (1,203 (ft) from ground level) at the project site from a pick in the nearest offset well, the Waterford Oil Co. No. 001 (SN 81236)., as discussed in *Section 1 – Site Characterization* Figure 3-2 displays a map of the location of the wells used to determine the USDW. This map is included in *Appendix B* as item *B-20 USDW Structure and Determination*.

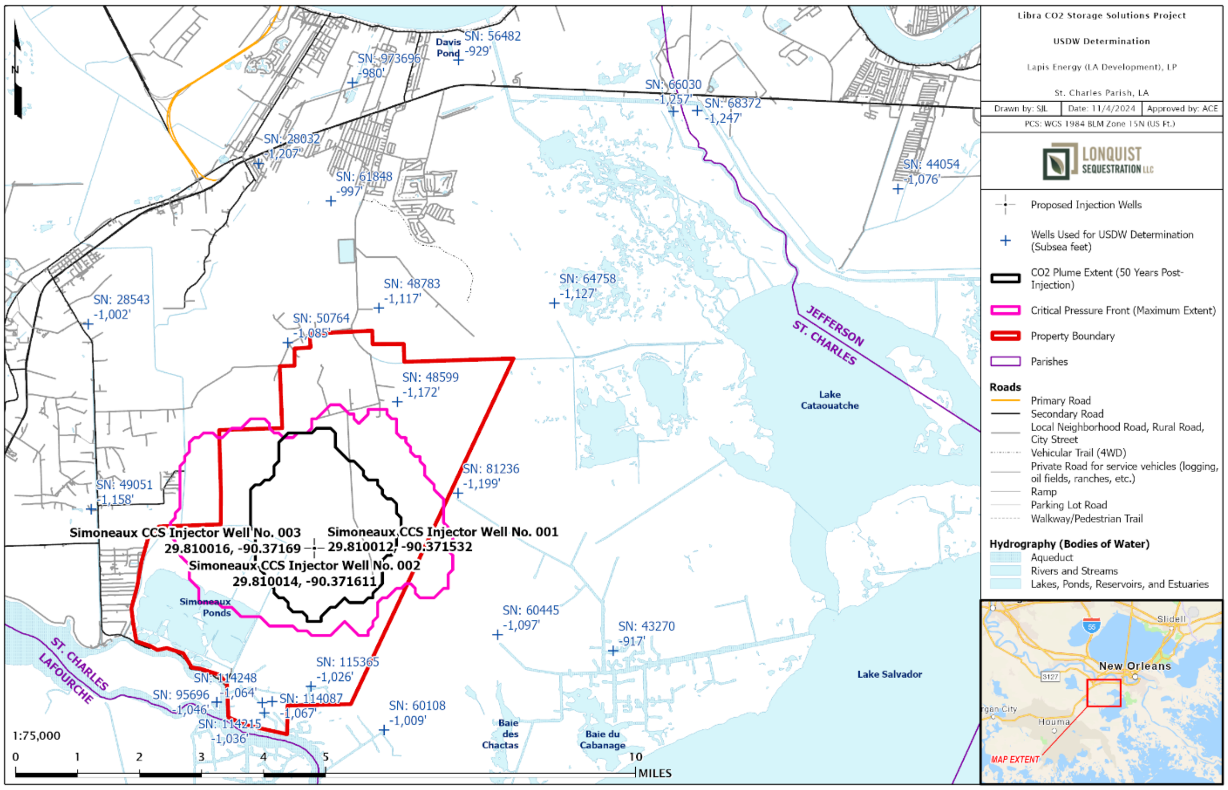


Figure 3-2 – USDW Determination Map

The methodology used to calculate the pressure front for the Libra project was developed by E.I. du Pont de Nemours & Co.. It has been verified and used by multiple Class I applications in the Gulf Coast to evaluate pressure fronts for at least 30 years. The fundamental assumption of this method is that the only potential pathway for fluid movement between the injection interval and USDWs is through artificial penetrations like active or inactive wells—in the absence of naturally occurring, vertically transmissive conduits like faults or fractures. Pressure increase in the injection interval must exceed the threshold pressure (critical pressure) required to displace the mud within the wellbore and overcome the minimum gel strength.

A static mud column generates hydrostatic pressure. For an abandoned well to facilitate fluid movement, the combined pressures from injection (Pi) and the original formation pressure (Pf) must exceed the pressure of the static mud column (Ps). Additionally, the gel strength pressure (Pg) of the mud in a static fluid column must be considered. Therefore, for fluid to move upward, the sum of the original formation pressure and injection pressure must be greater than the static fluid column pressure plus the mud's gel strength pressure. This relationship, show in Equations 1 through 3, is based on a simple balance of forces (Davis, 1986):

(Eq. 1)

$$Pf + Pi > Ps + Pg$$

Where:
Pf = original formation pressure (pounds per square inch gauge (psig))
Pi = formation pressure increase due to injection (psi)
Ps = static fluid column pressure (psig)
Pg = gel strength pressure (psi)

(Eq. 2)

$$Ps = 0.052 \cdot h \cdot M$$

Where:
h = depth to the injection reservoir from the 50 ft fallback
M = fluid weight (pounds per gallon (lb/gal))
0.052 = conversion factor so that Ps is in psi

(Eq. 3)

$$Pg = \frac{(0.00333 \cdot G \cdot h)}{d}$$

Where:
G = gel strength (pounds per 100 square feet (lb/100 ft^2))
d = borehole diameter (inches (in.))
0.00333 = conversion factor for Pg expressed in psi

A gel strength of 20 lb/100 ft^2 was used. Field evidence of the longevity of mud as a plugging material has been demonstrated during well reentries. The Nora Schulze No. 2, located in Nueces County, Texas, was reentered by Envirocorp in the late 1980s. The well was plugged and abandoned with 10.6 to 11.0 lb/gal mud when abandoned in 1959 . Mud samples were taken upon reentry to a depth of approximately 754 ft using tubing pushed into the mud column, starting from a depth of 120 ft. Below a depth of 754 ft, the mud could only be displaced from the well by breaking circulation (i.e., the tubing string could not be advanced) (.

The average mud weight of the recovered samples was 11.1 lb/gal, showing that the mud did not appreciably change over the intervening 29 years following original abandonment. The gel strengths of the samples ranged between 217 lb/100 ft^2 to greater than 320 lb/100 ft^2. These values are over an order of magnitude greater than the 20 lb/100 ft^2 value commonly used for abandoned well assessment purposes . In addition, shear strengths of the mud samples ranged from 170 lb/100 ft^2 to 7,000 lb/100 ft^2, increasing with depth .

For the gel-strength pressure calculation, all wellbores were considered open hole, which is a conservative approximation. For cased holes, the parameter "d" would equal the effective annular diameter (borehole diameter minus the outside casing diameter), which is significantly smaller, resulting in a higher calculated gel-strength pressure.

The conservative 50-ft fallback is an extra safety factor assuming the entire wellbore will not be filled with mud.

Nearby wells were examined to determine mud weights and wellbore diameters for wells in the project area, and this data was used for the above calculations. Taken from Table 2-12 in *Section 2 – Plume Model*, the lowest mud weight—9.3 pounds per gallon (ppg)—and wellbore diameter of 10 in. were used for the Libra project critical pressure front calculations.

These equations were input into the Petrel™ calculator to generate a critical threshold pressure grid, and a post-processing workflow was created to facilitate these calculations. Threshold pressures ranged from 25 psi to 272 psi from top to bottom of the grid.

Tables 3-2 through 3-4 provide the calculated values for each stage of the proposed Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively, for the Libra project.

Table 3-2 – Simoneaux CCS Injector Well No. 001 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
1	9,187	208
2	8,168	182

Table 3-3 – Simoneaux CCS Injector Well No. 002 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
1	7,181	157
2	6,838	149

Table 3-4 – Simoneaux CCS Injector Well No. 003 Critical Threshold Pressure for Each Completion Stage

Completion Stage	Depth to Top of Injection Zone (ft)	Critical Threshold Pressure (psi)
1	6,201	132
2	5,129	105

Figure 3-3 depicts the shape and lateral extent of the pressure front area.

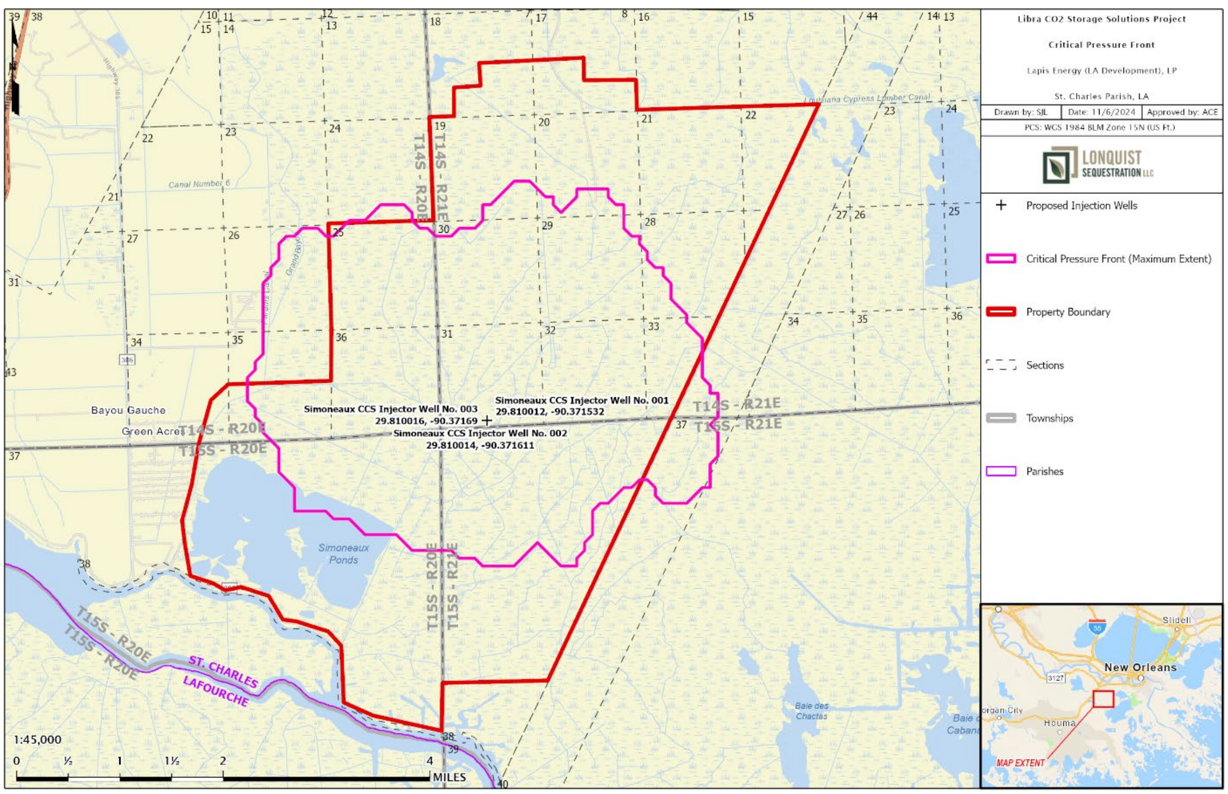


Figure 3-3 – Critical Pressure Front

3.3.3 Operating Strategies Influencing Reservoir Modeling Results

In an effort to limit lateral plume growth and keep the number of intercepted artificial penetrators to a minimum, a partitioned completion strategy was developed. Two completion stages are planned for each proposed injection well. Simoneaux CCS Injector Well No. 001 utilizes the deepest pore space in the Miocene sands. Simoneaux CCS Injector Wells No. 002 and No. 003 will inject into increasingly shallower sand intervals, but no well will inject into the same injection horizon as another well. This separation of injection zones helps to reduce the pressure buildup of having multiple wells injecting into the same zone.

Interbedded shale layers prevent vertical migration, allowing for the plume to stay stacked along the wellbore. This layering of shale ensures the containment of CO_2 within each injection interval. The stacking of these plumes increases the maximum injection potential of the formation. The Petrel outputs in Figures 3-4 and 3-5 show a south-north cross-sectional and oblique cross-sectional view, respectively, of the plume at 50 years post-injection.

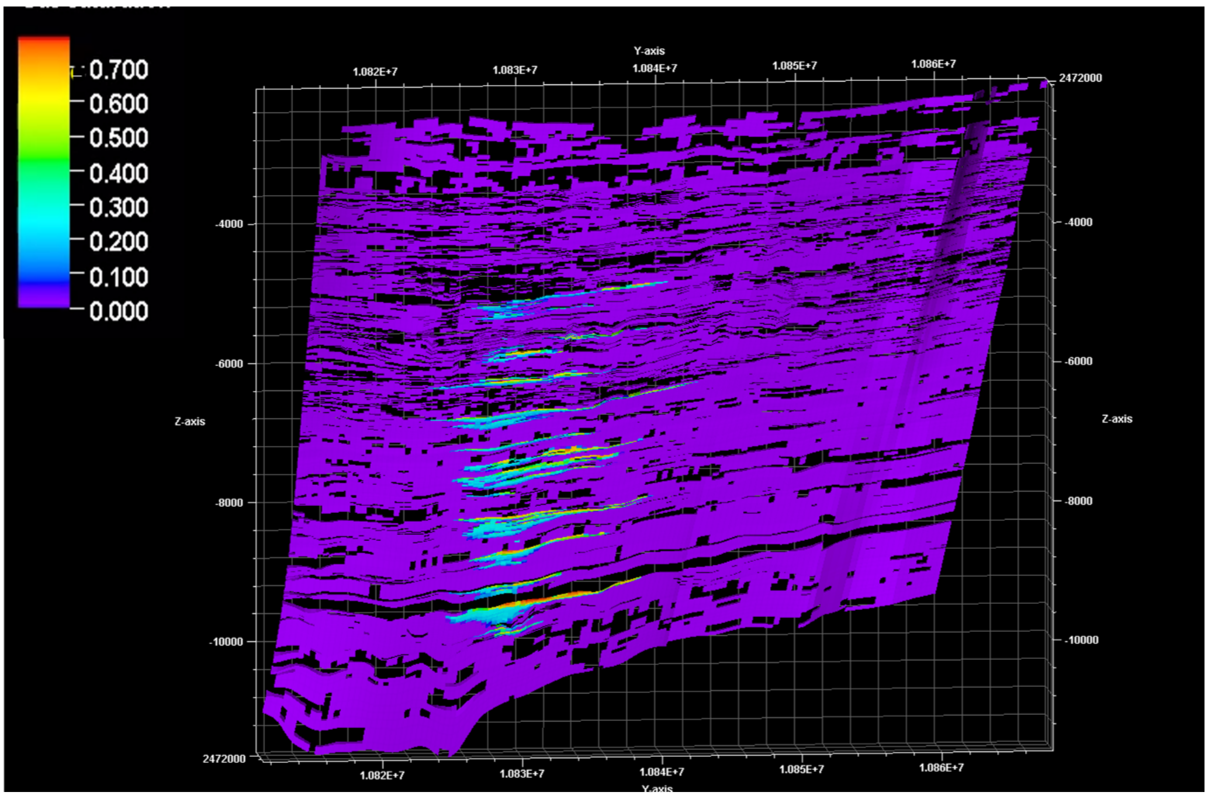


Figure 3-4 – Plume Model Results: South-North Cross-Sectional View

@ 50 years Post-Injection

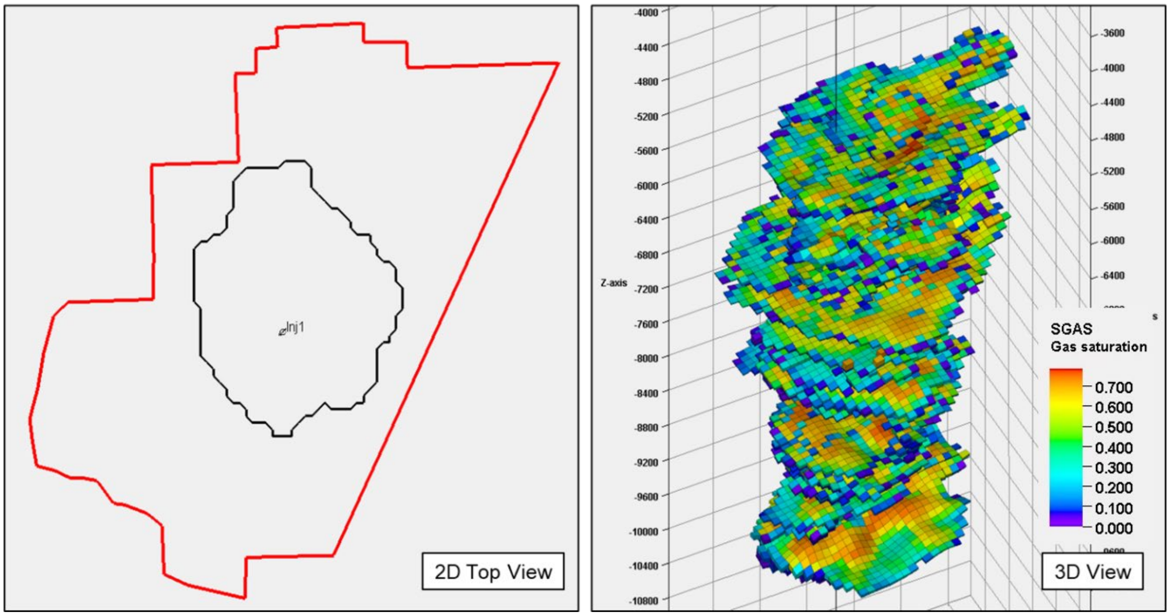


Figure 3-5 – Plume Model Results: Oblique Cross-Sectional Views

Figure 3-6 depicts the shape and lateral extent of the largest of the stacked injection plumes. This extent, in addition to the critical pressure area, was used to define the initial AOR for the proposed wells.

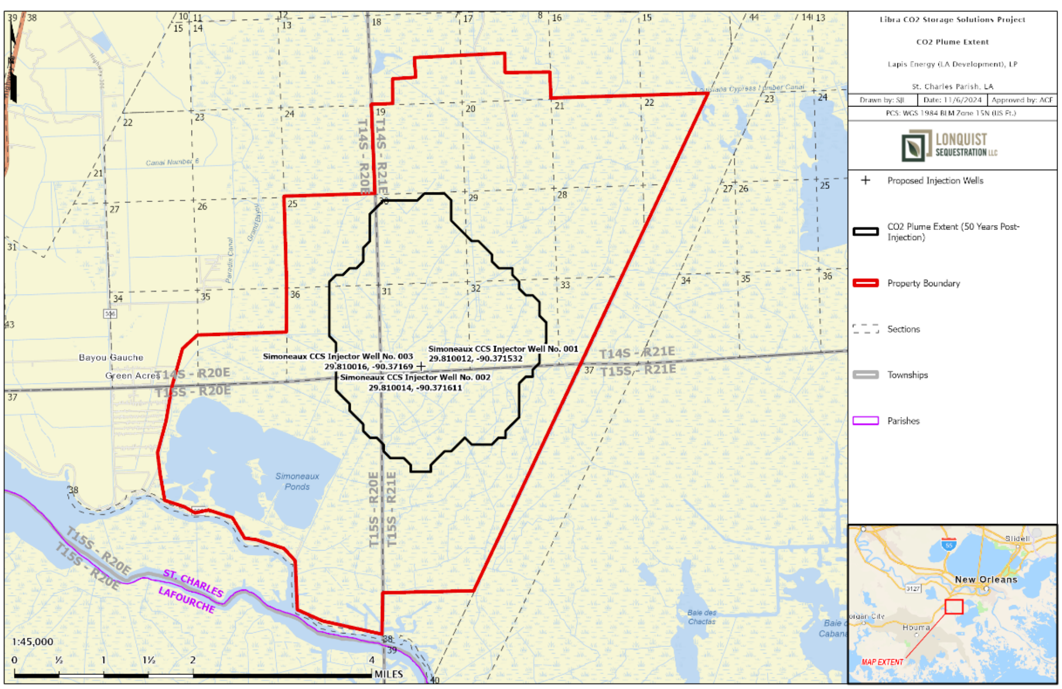


Figure 3-6 – Petrel Plume Model Results – Plan View Maximum Extent

This plume extent was digitized from the Petrel output and imported into ArcGIS to define the AOR for the Libra project. A thorough investigation was conducted to identify artificial penetrations or any other features that pose a threat to the lowermost USDW during injection activities or operational processes. During this review, maps were created to illustrate the AOR and the man-made structures found within its boundaries. Subsequently, these artificial penetrations and other man-made elements were evaluated based on their depth of completion, construction specifications, and the adequacy of plugging and abandonment (P&A) procedures. The goal of this assessment was to identify any penetrations that could potentially compromise the integrity of the storage intervals or USDW.

The maps and associated lists generated during this effort are contained in *Appendix C*. Figure 3-7 identifies the AOR for the project.

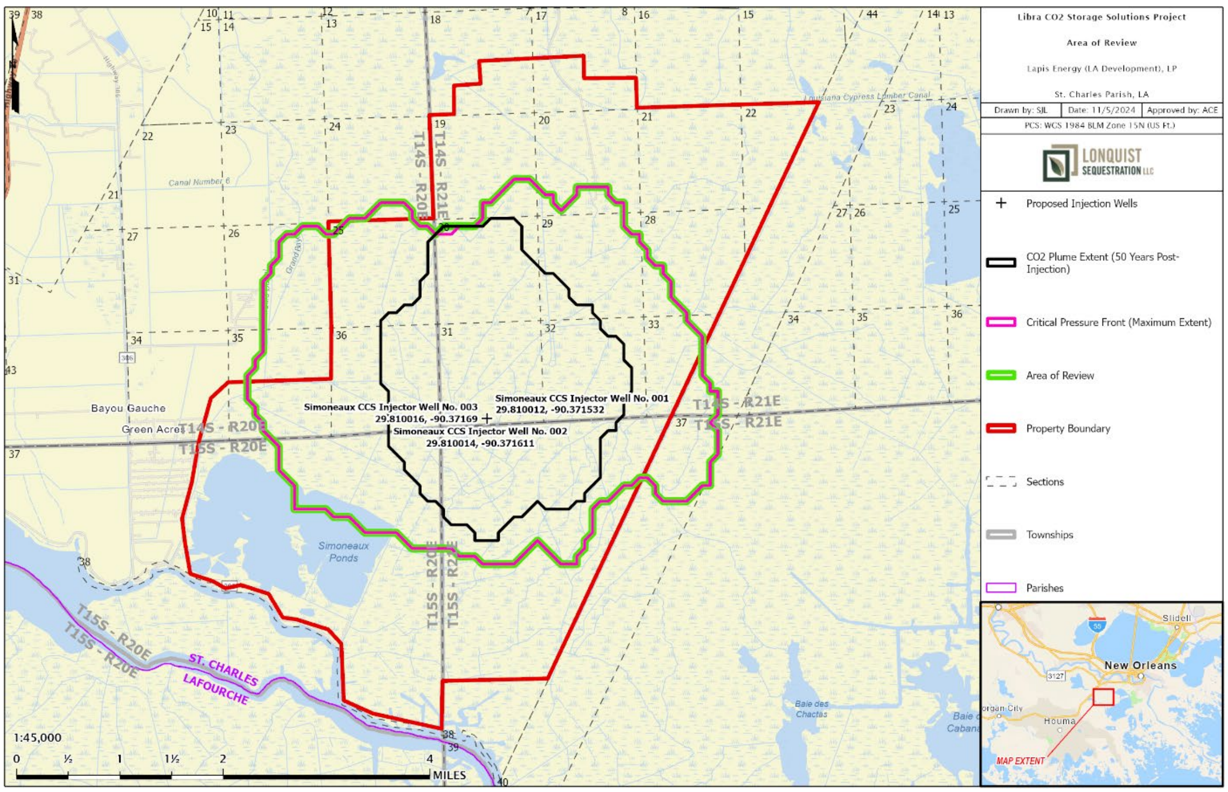


Figure 3-7 – Final AOR Map

3.3.4 Area of Review Results

The delineation of the AOR was established with the following three primary objectives:

1. Identification of artificial penetrations or man-made structures that may have an impact on the safe storage of sequestered gases for an indefinite period while safeguarding the USDW

2. Identification of subsurface geological features that may have an impact on the safe storage of sequestered gases for an indefinite period while protecting the USDW

3. Identification of pore space rights affected by the expansion of the CO_2 plume over the modeled time period

In accordance with SWO and EPA requirements, Lapis will reevaluate the AOR at each of the following intervals:

- Minimum frequency of 5 years
- Detection of a significant change in the plume
- As otherwise warranted by routine monitoring or operational conditions

During reevaluation, wells identified as requiring corrective action will be addressed with an amended AOR and Corrective Action Plan, to be submitted to the Commissioner of Conservation (Commissioner) for approval. All amendments and corrective action plans will be approved, incorporated into the permit, and subject to permit modification requirements.

Upon reevaluation, if no additional wells are identified, Lapis will provide to the Commissioner evidence backed by monitoring data and modeling results, indicating that no additions are necessary. All modeling inputs and data utilized to substantiate AOR reevaluations will be retained for 10 years.

A comprehensive multi-database analysis was performed to identify all artificial penetrations into the injection interval within the AOR. Well data for the AOR was gathered primarily from the LDENR Strategic Online Natural Resources Information System (SONRIS). Supplemental data was then obtained from other databases, including Enverus and IHS, to limit inaccuracies in the data and provide additional information. Water well data was accessed from the LDENR water well registration database.

As stated in *Section 0 – Introduction*, the proposed locations of the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 are ideally suited for carbon sequestration. The AOR evaluation yielded 21 artificial penetrations and 3 expired permit within the AOR boundaries. Of those, 10 will require limited corrective action to protect the USDW. Furthermore, it was determined that no subsurface geologic features exist within the AOR that may compromise the long-term storage of injected CO_2.

A map depicting the offset oil and gas wells is shown in Figure 3-8, and Table 3-5 details all of these wells within the AOR boundary that penetrate the UCZ. Well L B Simoneaux No. 01 (SN 186005) is included with well location details provided by an amended drilling permit and therefore will not align with the SONRIS public well file location. Also, wells Lydia B Simoneaux Et Al No. 25 (SN 210373) and L B Simoneaux No. 08 (SN 52499) were included in the critical pressure AOR list but the permits expired and the wells were not drilled. The Simoneaux No. 1

(SN 147163) is included in the oil and gas penetrations list, but the well drilling permit expired and the wellbore was not drilled. Finally, Wells Lydia B Simoneaux Et Al No. 007 (SN 51104) and the Lydia B Simoneaux Et Al No. 007-D (SN 76172) are an original hole and a sidetrack well. They are both listed on the table, yet share a single location.

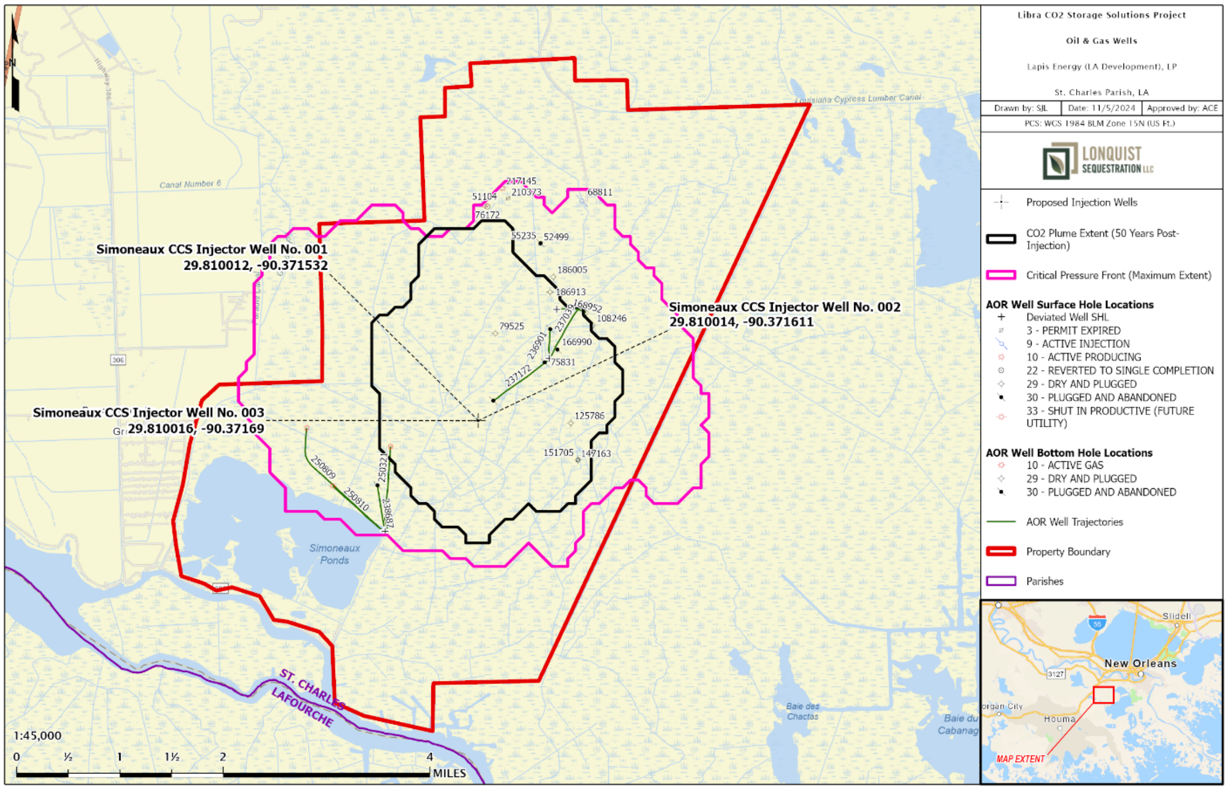


Figure 3-8 – Map of Oil and Gas Wells within the AOR

Table 3-5 – AOR Oil and Gas Wells List

Area of Review: Oil and Gas Well List											
SN	**Well Name**	**Well No.**	**Current Operator**	**S**	**T**	**R**	**Latitude NAD 27**	**Longitude NAD 27**	**Well Status**	**Total Depth (ft.)**	**Date Drilled**
75831	Lydia B. Simoneaux ET AL	15	Texaco Inc.	32	14S	21E	29°49'19.2"N	90°22'6.24"W	Plugged	14,676	8/23/1959
79525	Lydia B. Simoneaux ET AL	16	Texaco Inc.	31	14S	21E	29°48'33.12"N	90°21'23.759"W	Plugged	11,000	6/10/1960
125786	St. Charles LD & Trust Co.	01	Pan American Petroleum Corporation	32	14S	21E	29°49'4.079"N	90°21'38.159"W	Plugged	12,684	10/5/1968
166990	SJ Simoneaux	01	LLOG Exploration Co.	32	14S	21E	29°49'3.28"N	90°21'38.564"W	Plugged	11,776	2/7/1960
237172	Simoneaux Family Land LLC	03	Castex Energy	32	14S	21E	29°49'3.181"N	90°21'38.565"W	Plugged	12,005	2/27/2008
236901	Simoneaux Family Land LLC	01	Castex Energy	32	14S	21E	29°49'3.379"N	90°21'38.563"W	Plugged	11,445	2/3/2008
237039	Simoneaux Family Land LLC	02	Castex Energy	32	14S	21E	29°49'10.34"N	90°21'30.56"W	Plugged	13,057	3/31/2008
151705	Simoneaux	01	Edwin L. Cox	05	14S	21E	29°48'14.399"N	90°21'20.159"W	Plugged	12,140	4/28/1976
168952	L B Simoneaux ET AL	01	Inexco Oil Company	29	14S	21E	29°49'30.633"N	90°21'30.7362"W	Plugged	11,050	7/11/1980
186913	L B Simoneaux	02	Sandefer Petroleum	29	14S	21E	29°49'39.57"N	90°21'33.909"W	Plugged	11,265	7/11/1980
186005	L B Simoneaux	01	Sandefer Petroleum	29	14S	21E	29°49'47.045"N	90°21'31.849"W	Plugged	16,000	6/30/1983
108246	Mrs L B Simoneaux ET AL	01	Lacal Petroleum	32	14S	21E	29°49'22.08"N	90°21'9.719"W	Plugged	12,153	4/13/1965
55235	Lydia B Simoneaux ET Al	08	Forman Petroleum	29	14S	21E	29°50'4.2"N	90°21'38.88"W	Plugged	13,300	3/7/1955

SN	Well Name	Well No.	Current Operator	S	T	R	Latitude NAD 27	Longitude NAD 27	Well Status	Total Depth (ft.)	Date Drilled
51104	Lydia B Simoneaux Et Al	07	Vibe Resources LLC	19	14S	21E	29°50'24.062"N	90°21'10.801"W	Active	12,800	3/31/1954
76172	Lydia B Simoneaux Et Al	007-D	Vibe Resources LLC	19	14S	21E	29°50'24.062"N	90°21'10.801"W	Reverted to single completion	12,800	6/18/1959
217145	Lydia B Simoneaux	025	Vibe Resources LLC	19	14S	21E	29°50'32.275"N	90°22'0.282"W	Active	10,735	8/26/1995
68811	Lydia B Simoneaux ET AL SWD	011	Vibe Resources LLC	20	14S	21E	29°50'25.113"N	90°21'14.442"W	Active	11,650	1/8/1958
250809	Simoneaux Family Land LLC Well A	01	LLOX LLC	1	15S	20E	29°47'40.8978"N	90°23'13.5384"W	Active	14,221	6/24/2018
250810	Simoneaux Family Land LLC	02	LLOX LLC	1	15S	20E	29°47'40.83"N	90°23'13.5486"W	Active	12,729	3/9/2018
238687	Simoneaux Family Land LLC	05	Castex Energy	1	15S	20E	29°47'40.719"N	90°23'12.971"W	Plugged	12,024	10/7/2008
250321	Simoneaux Family Land LLC	01	LLOX LLC	1	15S	20E	29°47'40.6062"N	90°23'13.041"W	Active	12,827	6/20/2017
210373	Lydia B Simoneaux Et Al	025	Texaco, Inc.	19	14S	21E	29°50'27.262"N	90°21'57.075"W	Expired Permit	N/A	N/A
52499	L B Simoneaux	08	N/A	29	14S	21E	29°50'24.062"N	90°21'10.801"W	Expired Permit	N/A	N/A
147163	Simoneaux	1	Edwin L. Cox	5	15S	21E	29°48'14.399"N	90°21'20.159"W	Expired Permit	N/A	N/A

*NAD 27 – North American Datum of 1927
Blue highlighted wells are located in the CO_2 plume
Non-highlighted wells are located outside the CO_2 plume but in the critical pressure front

3.4 Corrective Action Plan and Schedule

The corrective action plan is engineered to confine wellbore and injectate fluids to within the injection zone and guarantee the safety of the USDW in any formations above the UCZ. To mitigate the risk of fluid migration, the plan for well reentry and rework will guarantee the long-term containment of CO_2 and other fluids to the permitted injection zone.

Within the AOR pore occupancy plume boundary, there are 10 wells that will be included in the Corrective Action Plan. Each well will be remediated in accordance with the design of the well; therefore, plans to remediate the wells will be unique and specifically engineered on a well-by-well basis. Wells Lydia B. Simoneaux Et Al No. 15, Lydia B. Simoneaux Et Al No. 16 St. Charles LD & Trust Co. No. 01, and Simoneaux Family Land LLC No. 01, No. 02, and No. 03 are provided with the proposed remediation plans. Operations to rework these wells will commence within 10 years following the injection commencement date, as the wells are not expected to be within the plume AOR until 2034. Additionally, wells SJ Simoneaux No. 01, Simoneaux No. 01, L B Simoneaux Et Al No. 01, and L B Simoneaux No. 02 will each be recompleted during the post-injection period of the project, with planned corrective action dates included in Table 3-6. The remediation operations for each well will utilize traditional and industry-approved plugging techniques to seal the wellbores and provide barriers to fluid migration out of zone.

The wells requiring reentry are included in Table 3-6. The wells that were provided in Table 3-5 and are not included in Table 3-6 are representative of wells plugged that will adequately prevent the movement of CO_2. In addition all the wells in Table 3-6 are located inside the boundary of the CO_2 plume front. There are no wells that require corrective action located outside the CO2 plume and in the critical pressure front.

Table 3-6 – Corrective Action Wells List

Well Name	Well No.	Serial No.	Location	Planned Corrective Action Method	Planned Corrective Date
Lydia B. Simoneaux ET AL	15	75831	Sec 32, T14S, R21E	Workover Reentry	Within 10 years of injection initiation
Lydia B. Simoneaux ET AL	16	79525	Sec 31, T14S, R21E	Workover Reentry	Within 10 years of injection initiation
St. Charles LD & Trust Co.	01	125786	Sec 32, T14S, R21E	Workover Reentry	Within 10 years of injection initiation
Simoneaux Family Land LLC	03	237172	Sec 32, T14S, R21E	Workover Reentry	Within 10 years of injection initiation
Simoneaux Family Land LLC	01	236901	Sec 32, T14S, R21E	Workover Reentry	Within 10 years of injection initiation
Simoneaux Family Land LLC	02	237039	Sec 32, T14S, R21E	Workover Reentry	Within 10 years of injection initiation

Well Name	Well No.	Serial No.	Location	Planned Corrective Action Method	Planned Corrective Date
SJ Simoneaux	01	166990	Sec 32, T14S, R21E	Workover Reentry	Within 5 years post-injection
Simoneaux	01	151705	Sec 05, T15S, R21E	Workover Reentry	Within 5 years post-injection
L B Simoneaux Et AL	01	168952	Sec 29, T14S, R21E	Workover Reentry	Within 30 years post-injection
L B Simoneaux	02	186913	Sec 29, T14S, R21E	Workover Reentry	Within 50 years post-injection
Simoneaux	01	147163	Sec 05, T15S, R21E	N/A – Expired Permit	N/A

The CO_2 plume growth and extent will be monitored and reevaluated periodically. A reassessment is planned to occur every 5 years, which will determine if amendments will have to be made to the Corrective Action Plan.

Site access for all the scheduled corrective action wells will be maintained to ensure that proper remediation can be performed when required.

3.4.1 General Reentry Process

The evaluation of the corrective action wells incorporates the documented coordinates, public well filings, casing specifications, cementing records, and P&A activities—and were used to develop the operational plans.

The wells identified within the AOR and that will require remediation were provided with plans for excavation, re-heading, and reentry workover operations. Data used to generate schematics was based on publicly available well files and, in some instances, is limited due to the age and documentation of the wells. For planning purposes, the well file information is assumed to be accurate; however, it is understood that a degree of risk exists due to improperly documented data. As a result, operational challenges can occur and are anticipated during the reentry work, and modification to scheduling and operational procedures will be necessary.

During the reentry process, wireline logging tools will be used to determine the integrity of the casing and quality of the cement within the cemented annulus. The logging intervals will be selected on an individual well basis to evaluate wellbore integrity across the intervals determined as critical to preventing CO_2 migration.

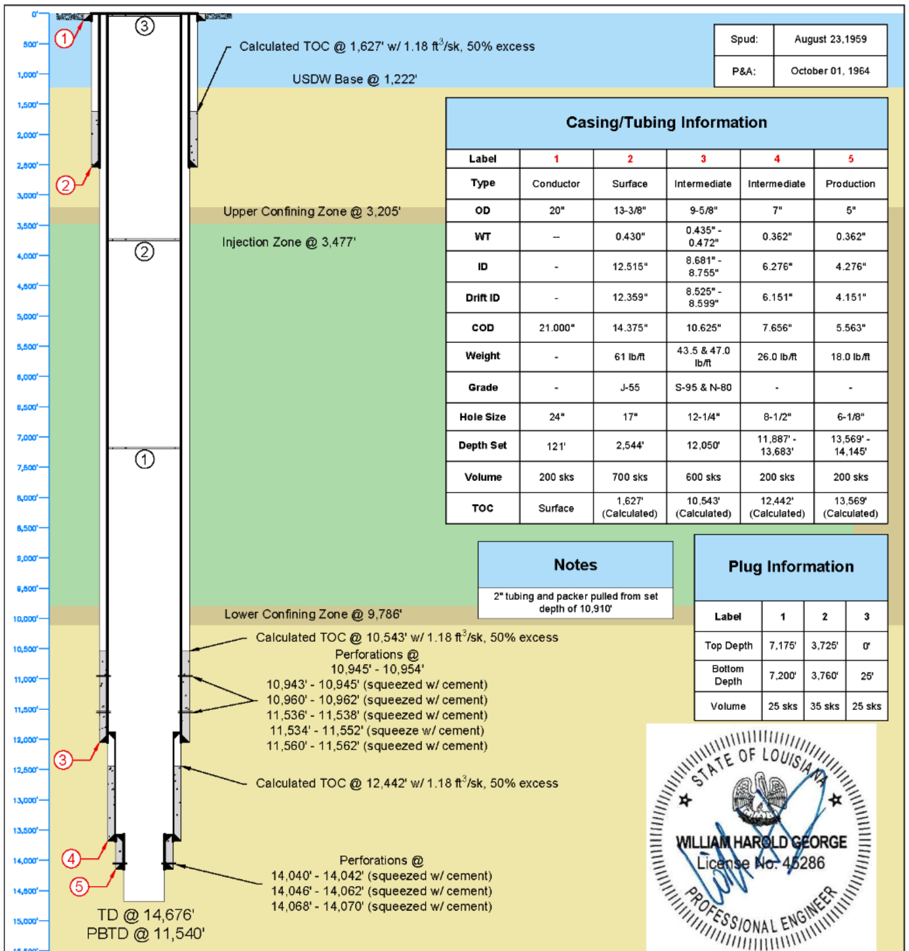
Each of the wells requiring reentry within the pore-occupancy plume will be reworked to provide multiple barriers. Remediation of the wells will meet the requirements of Class VI standards.

If the results from the cement bond logs (CBL) indicate that there is insufficient cement on the backside of the casing, a new plan will be developed in conjunction with the LDENR director.

Current and proposed wellbore schematics for each well that requires corrective action are provided in Figures 3-9 through 3-28.

3.4.2 In-Depth Review of Wells Needing Corrective Action

Well Name: Lydia B Simoneaux ET AL No. 15
Serial Number: 75831
API Number: 17-089-00225



Spud:	August 23,1959
P&A:	October 01, 1964

Casing/Tubing Information

Label	1	2	3	4	5
Type	Conductor	Surface	Intermediate	Intermediate	Production
OD	20"	13-3/8"	9-5/8"	7"	5"
WT	--	0.430"	0.435" - 0.472"	0.362"	0.362"
ID	-	12.515"	8.681" - 8.755"	6.276"	4.276"
Drift ID	-	12.359"	8.525" - 8.599"	6.151"	4.151"
COD	21.000"	14.375"	10.625"	7.656"	5.563"
Weight	-	61 lb/ft	43.5 & 47.0 lb/ft	26.0 lb/ft	18.0 lb/ft
Grade	-	J-55	S-95 & N-80	-	-
Hole Size	24"	17"	12-1/4"	8-1/2"	6-1/8"
Depth Set	121'	2,544'	12,050'	11,887' - 13,683'	13,569' - 14,145'
Volume	200 sks	700 sks	600 sks	200 sks	200 sks
TOC	Surface	1,627' (Calculated)	10,543' (Calculated)	12,442' (Calculated)	13,569' (Calculated)

Notes

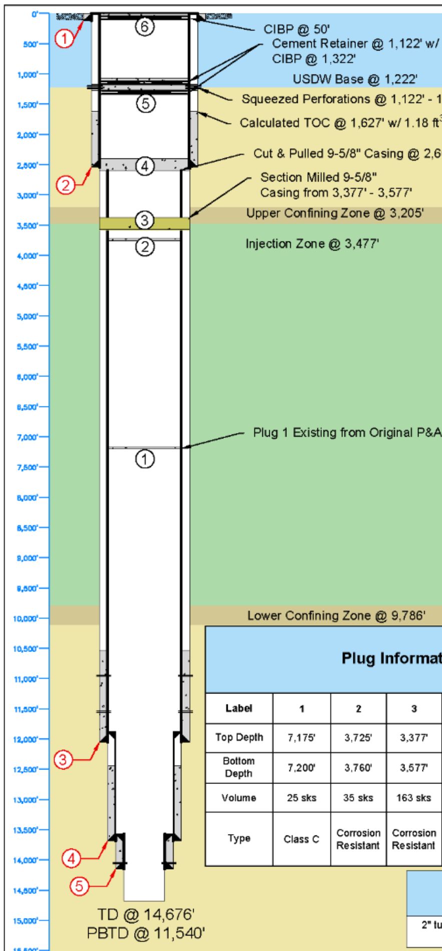
2" tubing and packer pulled from set depth of 10,910'

Plug Information

Label	1	2	3
Top Depth	7,175'	3,725'	0'
Bottom Depth	7,200'	3,760'	25'
Volume	25 sks	35 sks	25 sks

LONQUIST SEQUESTRATION LLC	Texaco Inc.	Lydia B Simoneaux ET AL Well 015	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 75831	**API:** 17-089-00225	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 4.84" N	**Long:** 90° 21' 38.47" W
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-9 – Lydia B Simoneaux ET AL No. 15 (SN 75831) Current State Schematic



Spud:	August 23,1959
P&A:	October 01, 1964

Casing/Tubing Information

Label	1	2	3	4	5
Type	Conductor	Surface	Intermediate	Intermediate	Production
OD	20"	13-3/8"	9-5/8"	7"	5"
WT	--	0.430"	0.435" - 0.472"	0.362"	0.362"
ID	-	12.515"	8.681" - 8.755"	6.276"	4.276"
Drift ID	-	12.359"	8.525" - 8.599"	6.151"	4.151"
COD	21.000"	14.375"	10.625"	7.656"	5.563"
Weight	-	61 lb/ft	43.5 & 47.0 lb/ft	26.0 lb/ft	18.0 lb/ft
Grade	-	J-55	S-95 & N-80	-	-
Hole Size	24"	17"	12-1/4"	8-1/2"	6-1/8"
Depth Set	121'	2,544'	12,050'	11,887' - 13,683'	13,569' - 14,145'
Volume	200 sks	700 sks	600 sks	200 sks	200 sks
TOC	Surface	1,627' (Calculated)	10,543' (Calculated)	12,442' (Calculated)	13,569' (Calculated)

Plug Information

Label	1	2	3	4	5	6
Top Depth	7,175'	3,725'	3,377'	2,400'	1,072'	0'
Bottom Depth	7,200'	3,760'	3,577'	2,600'	1,322'	50'
Volume	25 sks	35 sks	163 sks	133 sks	279 sks	33 sks
Type	Class C	Corrosion Resistant	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

Notes

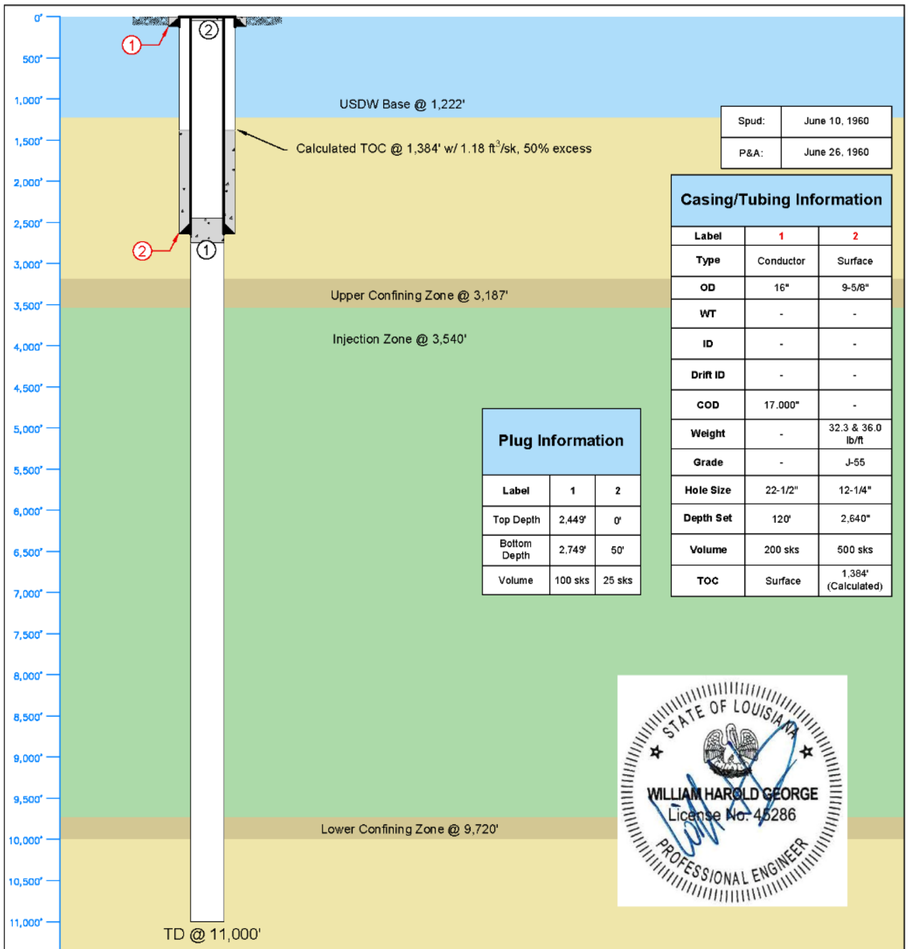
2" tubing and packer pulled from set depth of 10,910'

STATE OF LOUISIANA
WILLIAM HAROLD GEORGE
License No. 45286
PROFESSIONAL ENGINEER

LONQUIST SEQUESTRATION LLC	Lapis Energy (La Development), LP	Lydia B Simoneaux ET AL Well 015	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 75831	**API:** 17-089-00225	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 4.84" N	**Long:** 90° 21' 38.47" W
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-10 – Lydia B Simoneaux ET AL No. 15 (SN 75831) Corrective Action Schematic

Well Name: Lydia B Simoneaux ET AL No. 16
Serial Number: 79525
API Number: 17-089-00224



Spud:	June 10, 1960
P&A:	June 26, 1960

Casing/Tubing Information

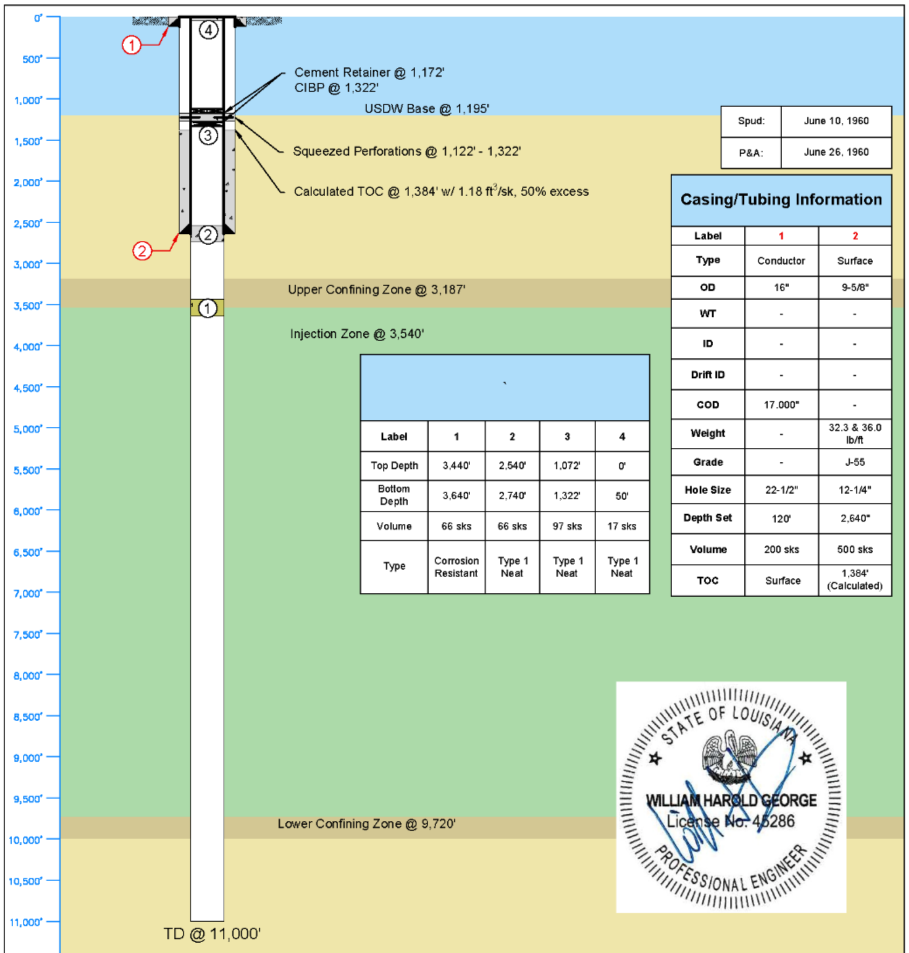
Label	1	2
Type	Conductor	Surface
OD	16"	9-5/8"
WT	-	-
ID	-	-
Drift ID	-	-
COD	17.000"	-
Weight	-	32.3 & 36.0 lb/ft
Grade	-	J-55
Hole Size	22-1/2"	12-1/4"
Depth Set	120'	2,640"
Volume	200 sks	500 sks
TOC	Surface	1,384' (Calculated)

Plug Information

Label	1	2
Top Depth	2,449'	0'
Bottom Depth	2,749'	50'
Volume	100 sks	25 sks

LONQUIST SEQUESTRATION LLC	Texaco Inc.	Lydia B Simoneaux ET AL Well 016	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 79525	**API:** 17-089-00224	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 19.97" N	**Long:** 90° 22' 6.56" W
Louisiana License EF5937	**Location:** S31, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-11 – Lydia B Simoneaux ET AL No. 16 (SN 79525) Current State Schematic



Spud:	June 10, 1960
P&A:	June 26, 1960

Label	1	2	3	4
Top Depth	3,440'	2,540'	1,072'	0'
Bottom Depth	3,640'	2,740'	1,322'	50'
Volume	66 sks	66 sks	97 sks	17 sks
Type	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

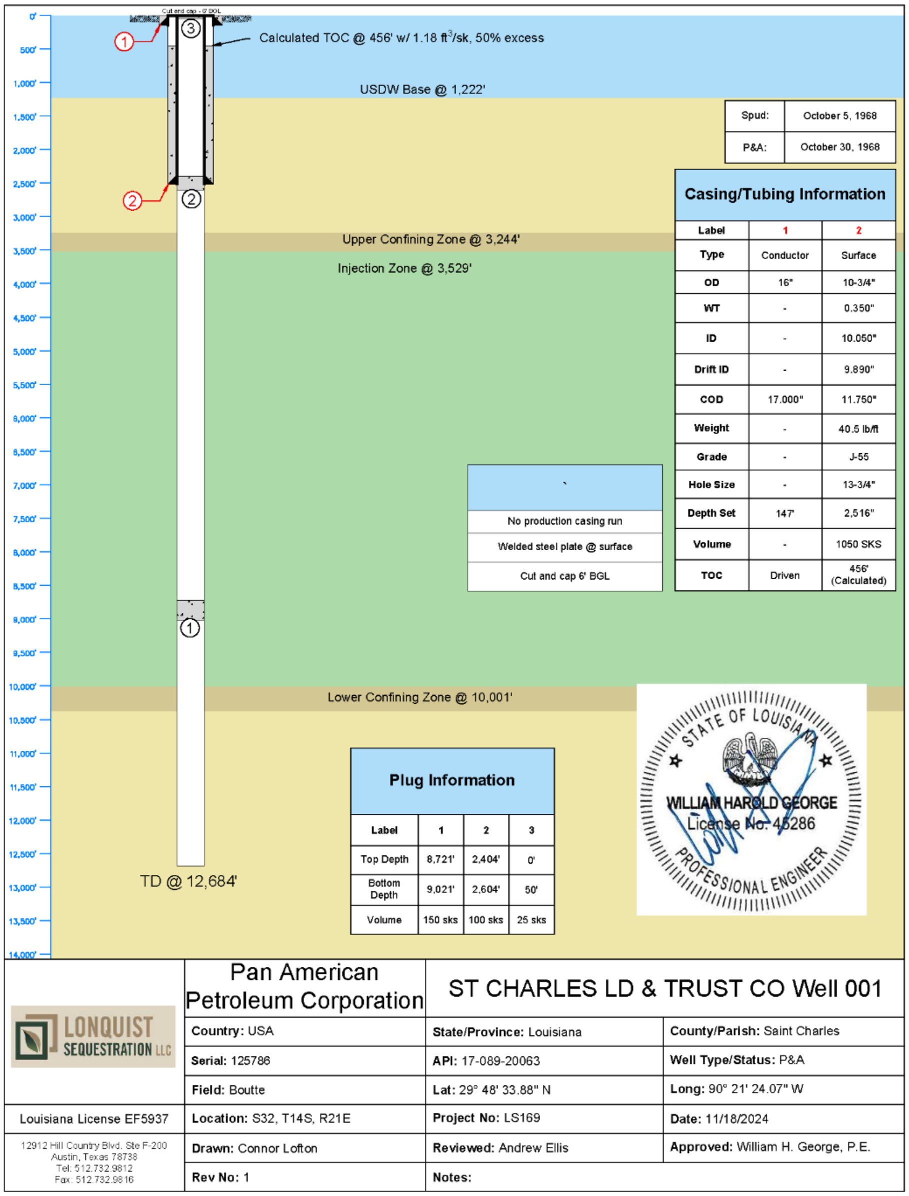
Casing/Tubing Information

Label	1	2
Type	Conductor	Surface
OD	16"	9-5/8"
WT	-	-
ID	-	-
Drift ID	-	-
COD	17.000"	-
Weight	-	32.3 & 36.0 lb/ft
Grade	-	J-55
Hole Size	22-1/2"	12-1/4"
Depth Set	120'	2,640"
Volume	200 sks	500 sks
TOC	Surface	1,384' (Calculated)

	Lapis Energy (LA Development, LP)	Lydia B Simoneaux ET AL Well 016	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 79525	**API:** 17-089-00224	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 19.97" N	**Long:** 90° 22' 6.56" W
Louisiana License EF5937	**Location:** S31, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-12 – Lydia B Simoneaux ET AL No. 16 (SN 79525) Corrective Action Schematic

Well Name: St. Charles LD & Trust Co. No. 01
Serial Number: 125786
API Number: 17-089-20063



Casing/Tubing Information

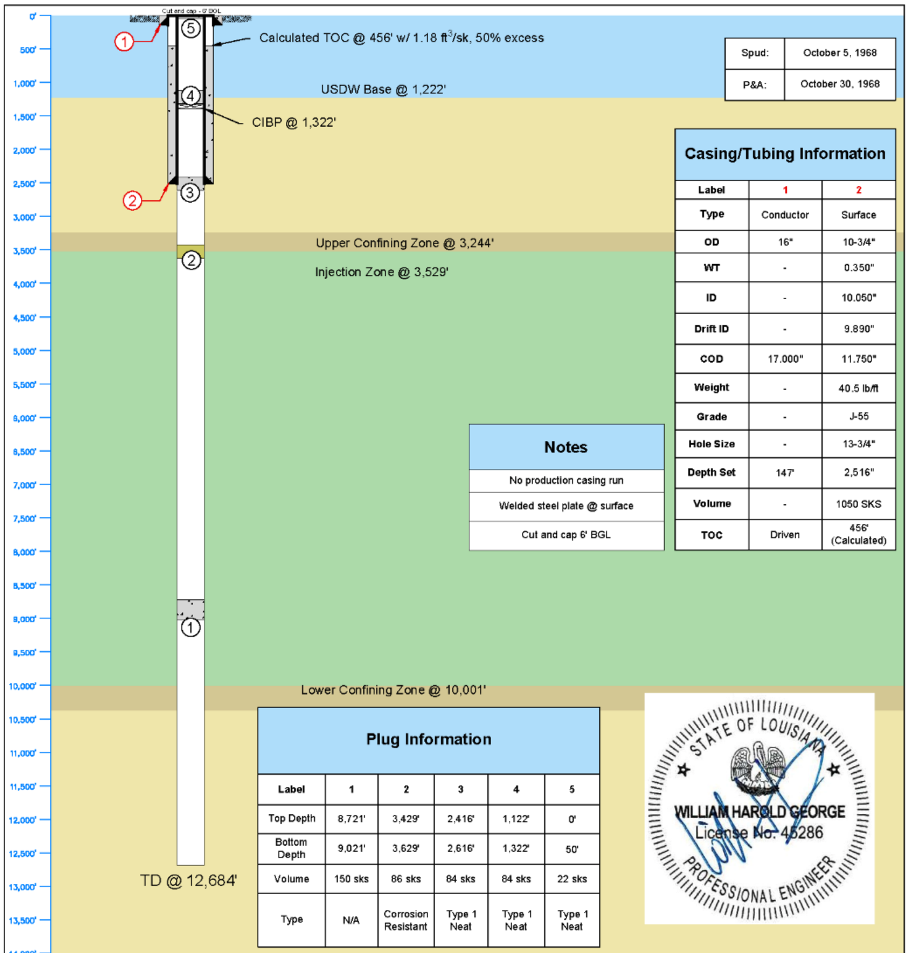
Label	1	2
Type	Conductor	Surface
OD	16"	10-3/4"
WT	-	0.350"
ID	-	10.050"
Drift ID	-	9.890"
COD	17.000"	11.750"
Weight	-	40.5 lb/ft
Grade	-	J-55
Hole Size	-	13-3/4"
Depth Set	147'	2,516"
Volume	-	1050 SKS
TOC	Driven	456' (Calculated)

Plug Information

Label	1	2	3
Top Depth	8,721'	2,404'	0'
Bottom Depth	9,021'	2,604'	50'
Volume	150 sks	100 sks	25 sks

Country: USA	State/Province: Louisiana	County/Parish: Saint Charles
Serial: 125786	API: 17-089-20063	Well Type/Status: P&A
Field: Boutte	Lat: 29° 48' 33.88" N	Long: 90° 21' 24.07" W
Location: S32, T14S, R21E	Project No: LS169	Date: 11/18/2024
Drawn: Connor Lofton	Reviewed: Andrew Ellis	Approved: William H. George, P.E.
Rev No: 1	Notes:	

Figure 3-13 – St. Charles LD & Trust Co. No. 01 (SN 125786) Current State Schematic



Spud:	October 5, 1968
P&A:	October 30, 1968

Casing/Tubing Information

Label	1	2
Type	Conductor	Surface
OD	16"	10-3/4"
WT	-	0.350"
ID	-	10.050"
Drift ID	-	9.890"
COD	17.000"	11.750"
Weight	-	40.5 lb/ft
Grade	-	J-55
Hole Size	-	13-3/4"
Depth Set	147'	2,516'
Volume	-	1050 SKS
TOC	Driven	456' (Calculated)

Notes

Notes
No production casing run
Welded steel plate @ surface
Cut and cap 6' BGL

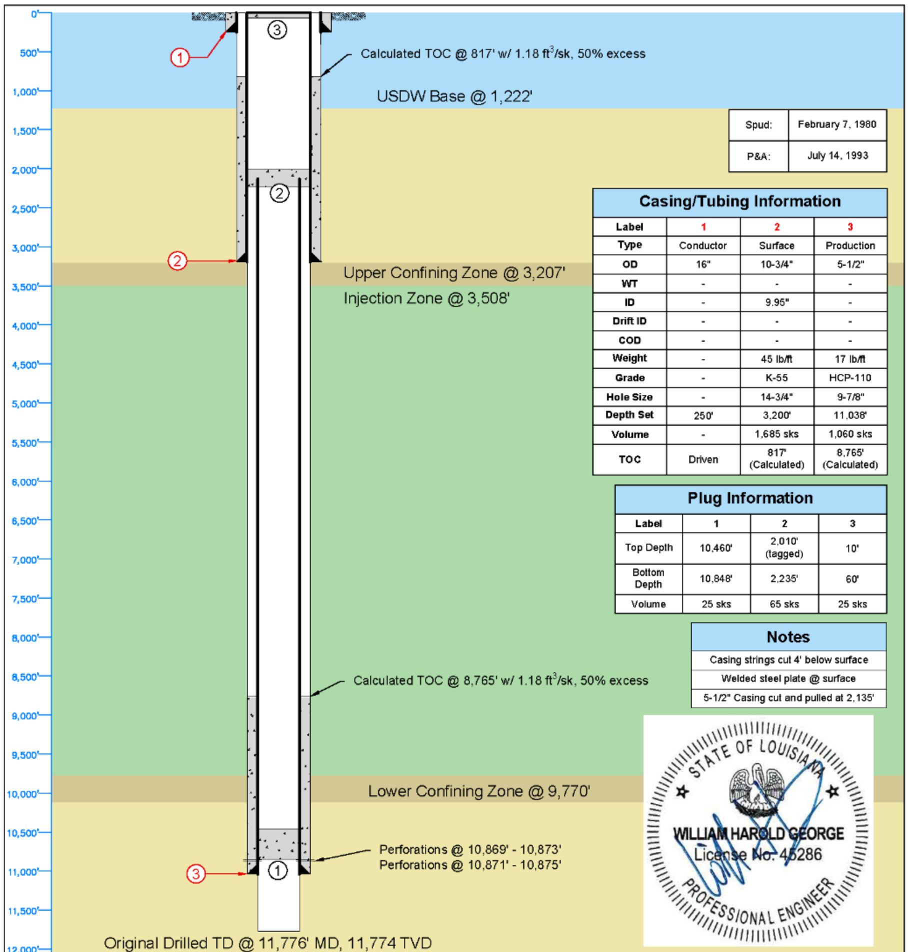
Plug Information

Label	1	2	3	4	5
Top Depth	8,721'	3,429'	2,416'	1,122'	0'
Bottom Depth	9,021'	3,629'	2,616'	1,322'	50'
Volume	150 sks	86 sks	84 sks	84 sks	22 sks
Type	N/A	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

	Lapis Energy (LA Development), LP	ST CHARLES LD & TRUST CO Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 125786	**API:** 17-089-20063	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 48' 33.88" N	**Long:** 90° 21' 24.07" W
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-14 – St. Charles LD & Trust Co. No. 01 (SN 125786) Corrective Action Schematic

Well Name: SJ Simoneaux No. 01
Serial Number: 166990
API Number: 17-089-20406



Spud:	February 7, 1980
P&A:	July 14, 1993

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	-	-
ID	-	9.95"	-
Drift ID	-	-	-
COD	-	-	-
Weight	-	45 lb/ft	17 lb/ft
Grade	-	K-55	HCP-110
Hole Size	-	14-3/4"	9-7/8"
Depth Set	250'	3,200'	11,038'
Volume	-	1,685 sks	1,060 sks
TOC	Driven	817' (Calculated)	8,765' (Calculated)

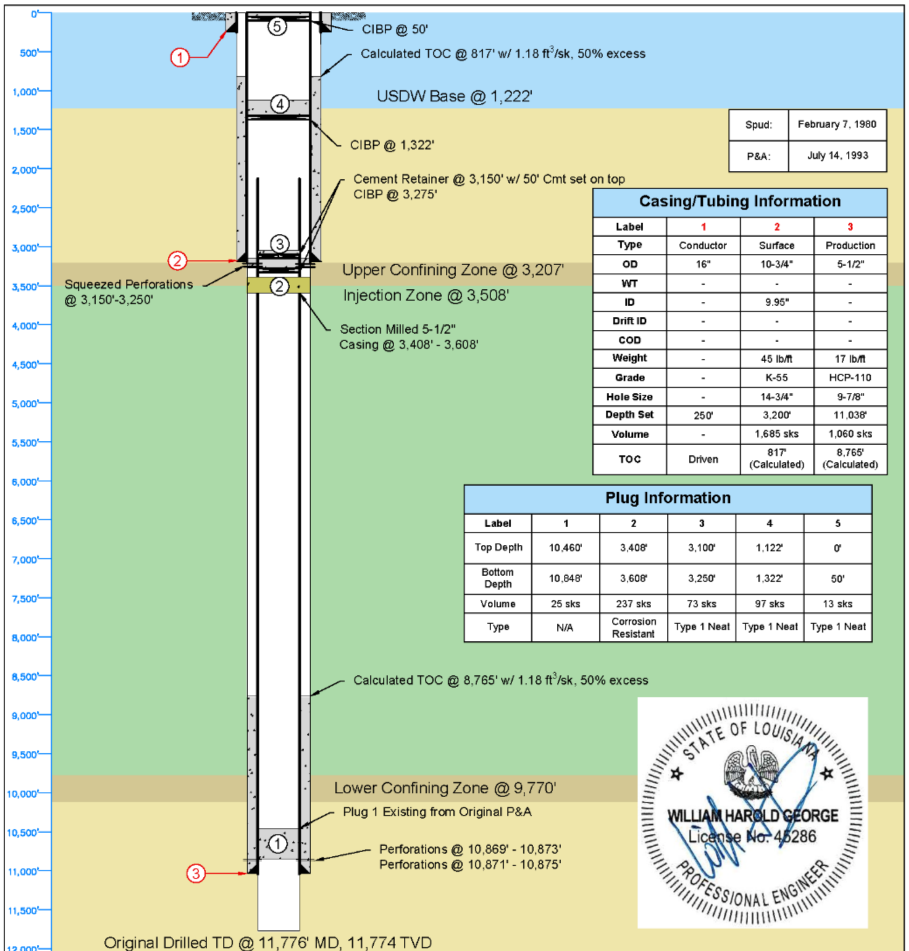
Plug Information

Label	1	2	3
Top Depth	10,460'	2,010' (tagged)	10'
Bottom Depth	10,848'	2,235'	60'
Volume	25 sks	65 sks	25 sks

Notes
Casing strings cut 4' below surface
Welded steel plate @ surface
5-1/2" Casing cut and pulled at 2,135'

LONQUIST SEQUESTRATION LLC	LLOG Exploration Co.	SJ SIMONEAUX Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 166990	**API:** 17-089-20406	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 10.34" N	**Long:** 90° 21' 30.56" W
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd, Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-15 – SJ Simoneaux No. 01 (SN 166990) Current State Schematic



Spud:	February 7, 1980
P&A:	July 14, 1993

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	-	-
ID	-	9.95"	-
Drift ID	-	-	-
COD	-	-	-
Weight	-	45 lb/ft	17 lb/ft
Grade	-	K-55	HCP-110
Hole Size	-	14-3/4"	9-7/8"
Depth Set	250'	3,200'	11,038'
Volume	-	1,685 sks	1,060 sks
TOC	Driven	817' (Calculated)	8,765' (Calculated)

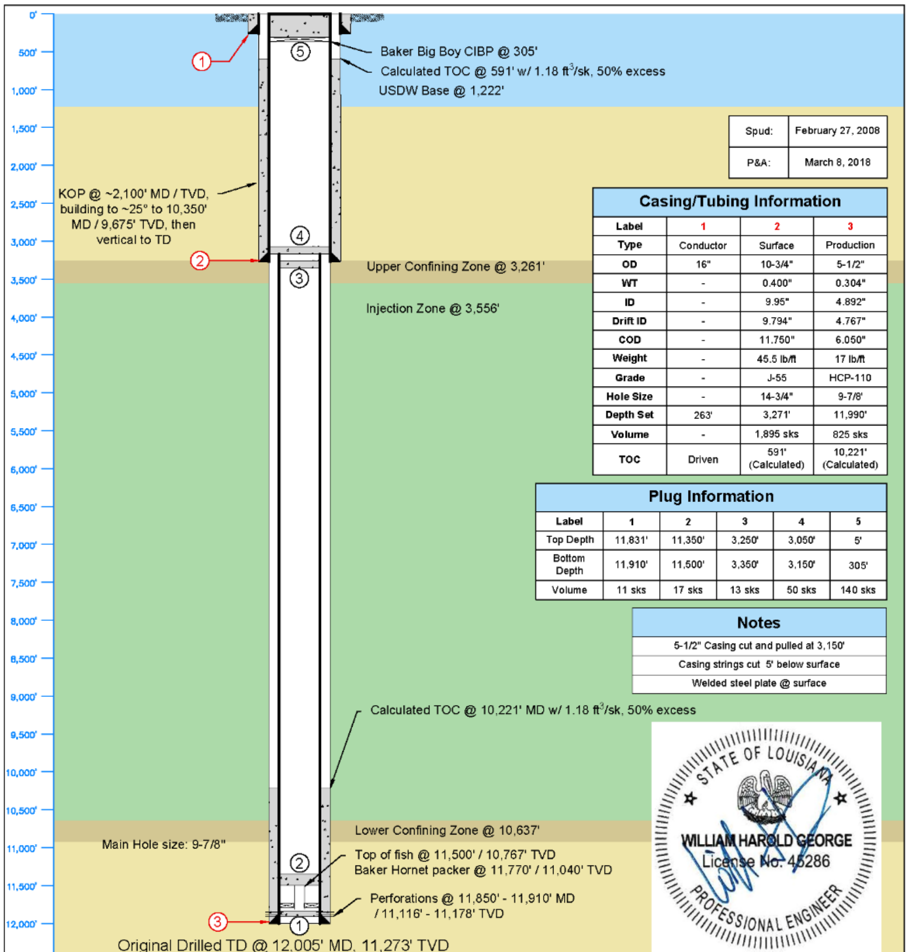
Plug Information

Label	1	2	3	4	5
Top Depth	10,460'	3,408'	3,100'	1,122'	0'
Bottom Depth	10,848'	3,608'	3,250'	1,322'	50'
Volume	25 sks	237 sks	73 sks	97 sks	13 sks
Type	N/A	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	SJ SIMONEAUX Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 166990	**API:** 17-089-20406	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 10.34" N	**Long:** 90° 21' 30.56" W
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-16 – SJ Simoneaux No. 01 (SN 166990) Corrective Action Schematic

Well Name: Simoneaux Family Land LLC No. 03
Serial Number: 237172
API Number: 17-089-20634



Spud:	February 27, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	0.400"	0.304"
ID	-	9.95"	4.892"
Drift ID	-	9.794"	4.767"
COD	-	11.750"	6.050"
Weight	-	45.5 lb/ft	17 lb/ft
Grade	-	J-55	HCP-110
Hole Size	-	14-3/4"	9-7/8'
Depth Set	263'	3,271'	11,990'
Volume	-	1,895 sks	825 sks
TOC	Driven	591' (Calculated)	10,221' (Calculated)

Plug Information

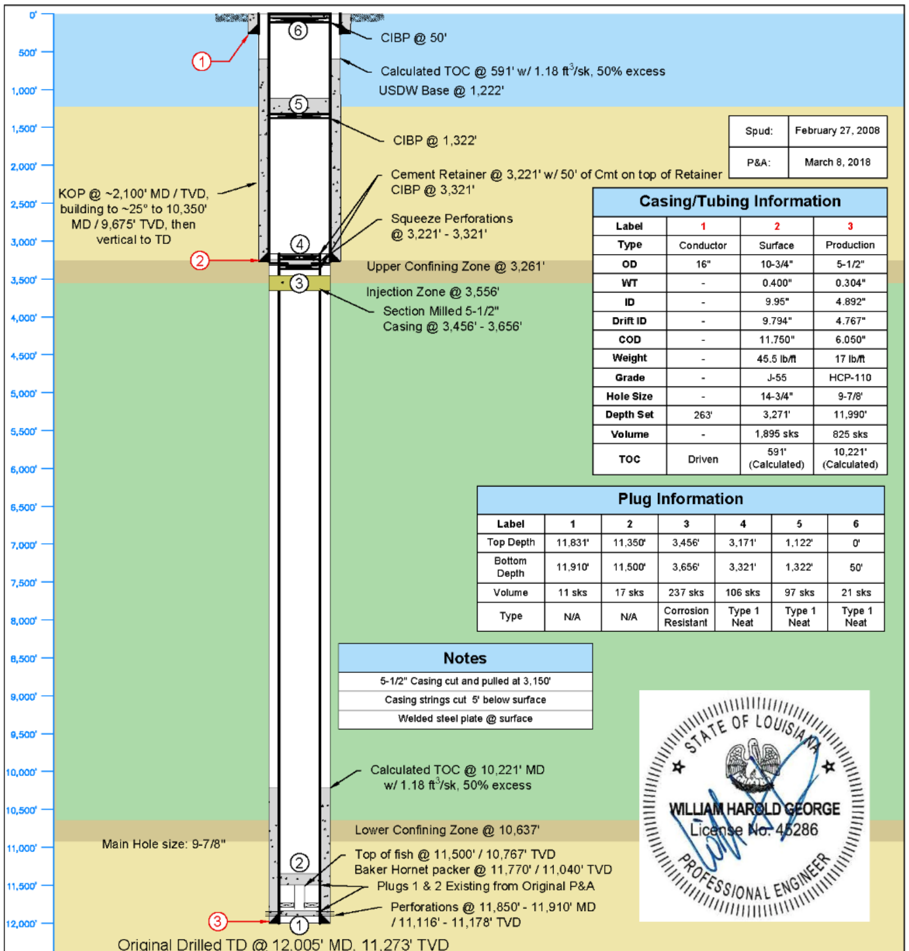
Label	1	2	3	4	5
Top Depth	11,831'	11,350'	3,250'	3,050'	5'
Bottom Depth	11,910'	11,500'	3,350'	3,150'	305'
Volume	11 sks	17 sks	13 sks	50 sks	140 sks

Notes

Notes
5-1/2" Casing cut and pulled at 3,150'
Casing strings cut 5' below surface
Welded steel plate @ surface

LONQUIST SEQUESTRATION LLC	Castex Energy	SIMONEAUX FAMILY LAND LLC Well 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 237172	**API:** 17-089-20634	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3" N (NAD 27)	**Long:** 90° 21' 39" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd, Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-17 – Simoneaux Family Land LLC No. 03 (SN 237172) Current State Schematic



Spud:	February 27, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	0.400"	0.304"
ID	-	9.95"	4.892"
Drift ID	-	9.794"	4.767"
COD	-	11.750"	6.050"
Weight	-	45.5 lb/ft	17 lb/ft
Grade	-	J-55	HCP-110
Hole Size	-	14-3/4"	9-7/8'
Depth Set	263'	3,271'	11,990'
Volume	-	1,895 sks	825 sks
TOC	Driven	591' (Calculated)	10,221' (Calculated)

Plug Information

Label	1	2	3	4	5	6
Top Depth	11,831'	11,350'	3,456'	3,171'	1,122'	0'
Bottom Depth	11,910'	11,500'	3,656'	3,321'	1,322'	50'
Volume	11 sks	17 sks	237 sks	106 sks	97 sks	21 sks
Type	N/A	N/A	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

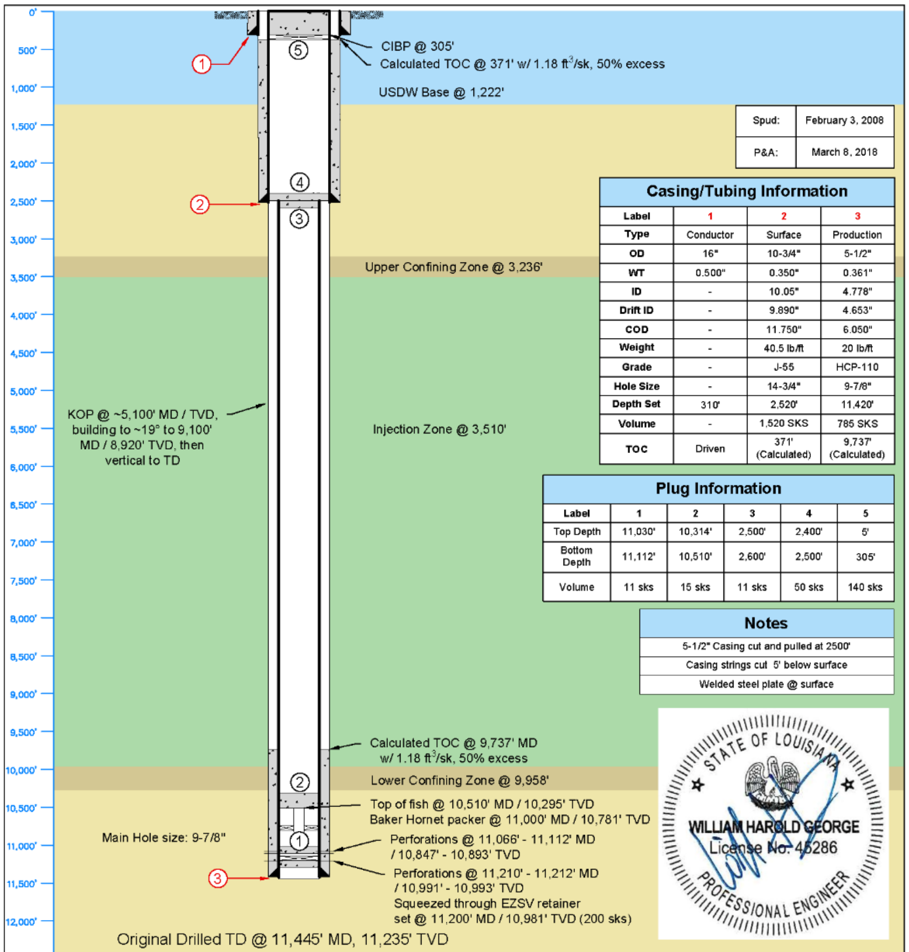
Notes

5-1/2" Casing cut and pulled at 3,150'
Casing strings cut 5' below surface
Welded steel plate @ surface

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	SIMONEAUX FAMILY LAND LLC Well 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 237172	**API:** 17-089-20634	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3" N (NAD 27)	**Long:** 90° 21' 39" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-18 – Simoneaux Family Land LLC No. 03 (SN 237172) Corrective Action Schematic

Well Name: Simoneaux Family Land LLC No. 01
Serial Number: 236901
API Number: 17-089-20632



Spud:	February 3, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	0.500"	0.350"	0.361"
ID	-	10.05"	4.778"
Drift ID	-	9.890"	4.653"
COD	-	11.750"	6.050"
Weight	-	40.5 lb/ft	20 lb/ft
Grade	-	J-55	HCP-110
Hole Size	-	14-3/4"	9-7/8"
Depth Set	310'	2,520'	11,420'
Volume	-	1,520 SKS	785 SKS
TOC	Driven	371' (Calculated)	9,737' (Calculated)

Plug Information

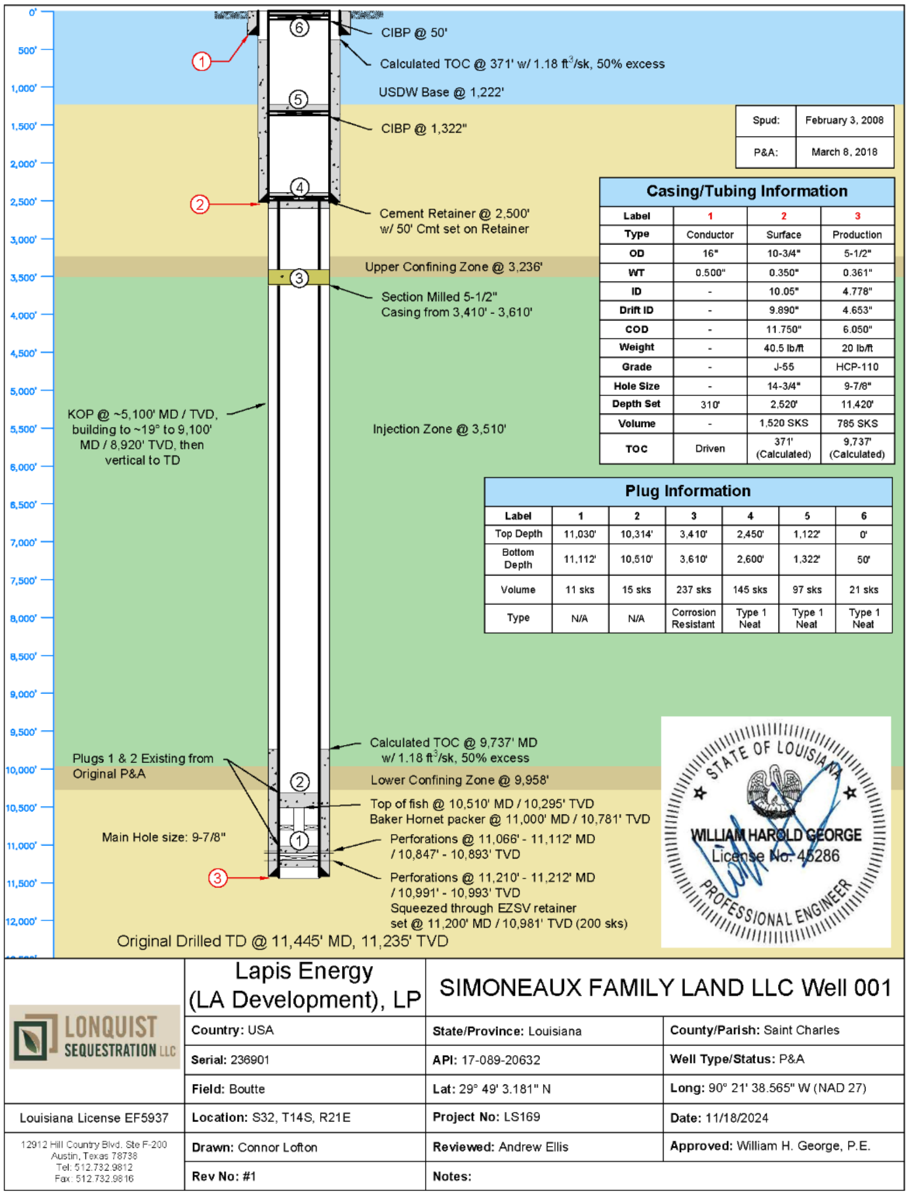
Label	1	2	3	4	5
Top Depth	11,030'	10,314'	2,500'	2,400'	5'
Bottom Depth	11,112'	10,510'	2,600'	2,500'	305'
Volume	11 sks	15 sks	11 sks	50 sks	140 sks

Notes

Notes
5-1/2" Casing cut and pulled at 2500'
Casing strings cut 5' below surface
Welded steel plate @ surface

LONQUIST SEQUESTRATION LLC	Castex Energy	SIMONEAUX FAMILY LAND LLC Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 236901	**API:** 17-089-20632	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3.181" N	**Long:** 90° 21' 38.565" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-19 – Simoneaux Family Land LLC No. 01 (SN 236901) Current State Schematic



Spud:	February 3, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	0.500"	0.350"	0.361"
ID	-	10.05"	4.778"
Drift ID	-	9.890"	4.653"
COD	-	11.750"	6.050"
Weight	-	40.5 lb/ft	20 lb/ft
Grade	-	J-55	HCP-110
Hole Size	-	14-3/4"	9-7/8"
Depth Set	310'	2,520'	11,420'
Volume	-	1,520 SKS	785 SKS
TOC	Driven	371' (Calculated)	9,737' (Calculated)

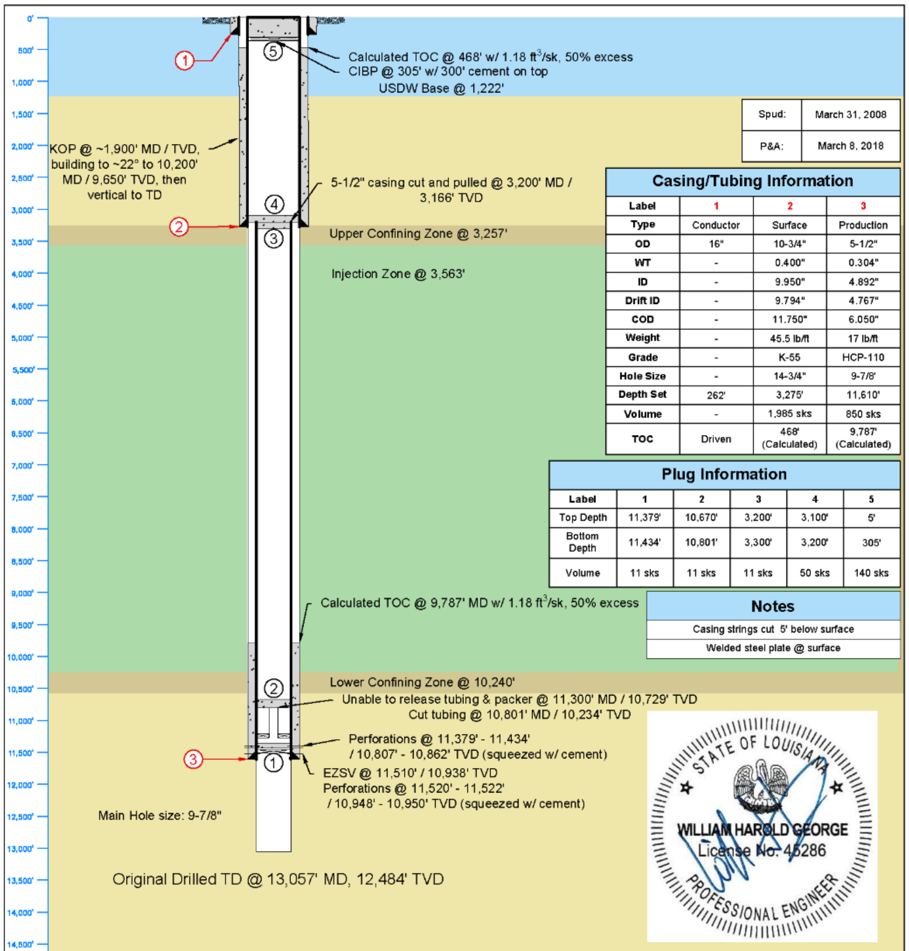
Plug Information

Label	1	2	3	4	5	6
Top Depth	11,030'	10,314'	3,410'	2,450'	1,122'	0'
Bottom Depth	11,112'	10,510'	3,610'	2,600'	1,322'	50'
Volume	11 sks	15 sks	237 sks	145 sks	97 sks	21 sks
Type	N/A	N/A	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

	Lapis Energy (LA Development), LP	SIMONEAUX FAMILY LAND LLC Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 236901	**API:** 17-089-20632	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3.181" N	**Long:** 90° 21' 38.565" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-20 – Simoneaux Family Land LLC No. 01 (SN 236901) Corrective Action Schematic

Well Name: Simoneaux Family Land LLC No. 02
Serial Number: 237039
API Number: 17-089-20633



Spud:	March 31, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	0.400"	0.304"
ID	-	9.950"	4.892"
Drift ID	-	9.794"	4.767"
COD	-	11.750"	6.050"
Weight	-	45.5 lb/ft	17 lb/ft
Grade	-	K-55	HCP-110
Hole Size	-	14-3/4"	9-7/8'
Depth Set	262'	3,275'	11,610'
Volume	-	1,985 sks	850 sks
TOC	Driven	468' (Calculated)	9,787' (Calculated)

Plug Information

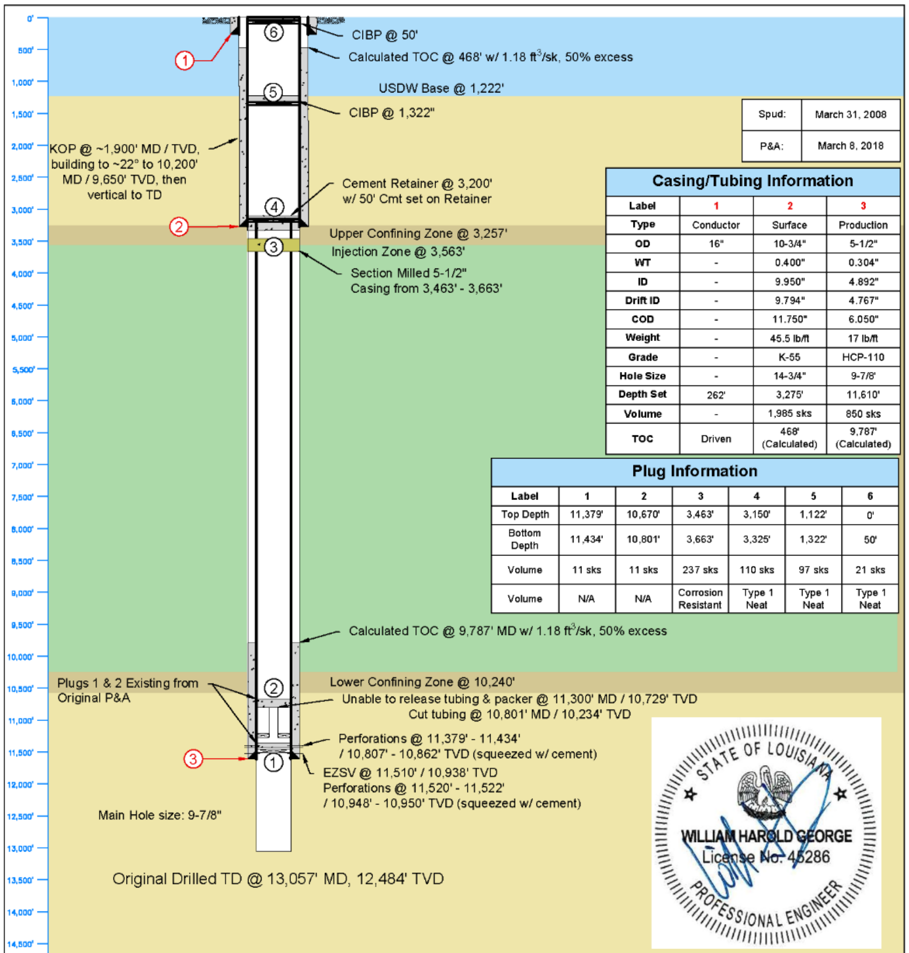
Label	1	2	3	4	5
Top Depth	11,379'	10,670'	3,200'	3,100'	5'
Bottom Depth	11,434'	10,801'	3,300'	3,200'	305'
Volume	11 sks	11 sks	11 sks	50 sks	140 sks

Notes

Notes
Casing strings cut 5' below surface
Welded steel plate @ surface

LONQUIST SEQUESTRATION LLC	Castex Energy	SIMONEAUX FAMILY LAND LLC Well 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 237039	**API:** 17-089-20633	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3.379" N (NAD 27)	**Long:** 90° 21' 38.563" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd, Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-21 – Simoneaux Family Land LLC No. 02 (SN 237039) Current State Schematic



Spud:	March 31, 2008
P&A:	March 8, 2018

Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	16"	10-3/4"	5-1/2"
WT	-	0.400"	0.304"
ID	-	9.950"	4.892"
Drift ID	-	9.794"	4.767"
COD	-	11.750"	6.050"
Weight	-	45.5 lb/ft	17 lb/ft
Grade	-	K-55	HCP-110
Hole Size	-	14-3/4"	9-7/8'
Depth Set	262'	3,275'	11,610'
Volume	-	1,985 sks	850 sks
TOC	Driven	468' (Calculated)	9,787' (Calculated)

Plug Information

Label	1	2	3	4	5	6
Top Depth	11,379'	10,670'	3,463'	3,150'	1,122'	0'
Bottom Depth	11,434'	10,801'	3,663'	3,325'	1,322'	50'
Volume	11 sks	11 sks	237 sks	110 sks	97 sks	21 sks
Volume	N/A	N/A	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	SIMONEAUX FAMILY LAND LLC Well 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 237039	**API:** 17-089-20633	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 3.379" N (NAD 27)	**Long:** 90° 21' 38.563" W (NAD 27)
Louisiana License EF5937	**Location:** S32, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-22 – Simoneaux Family Land LLC No. 02 (SN 237039) Corrective Action Schematic

Well Name: Simoneaux No. 01
Serial Number: 151705
API Number: 17-089-20292

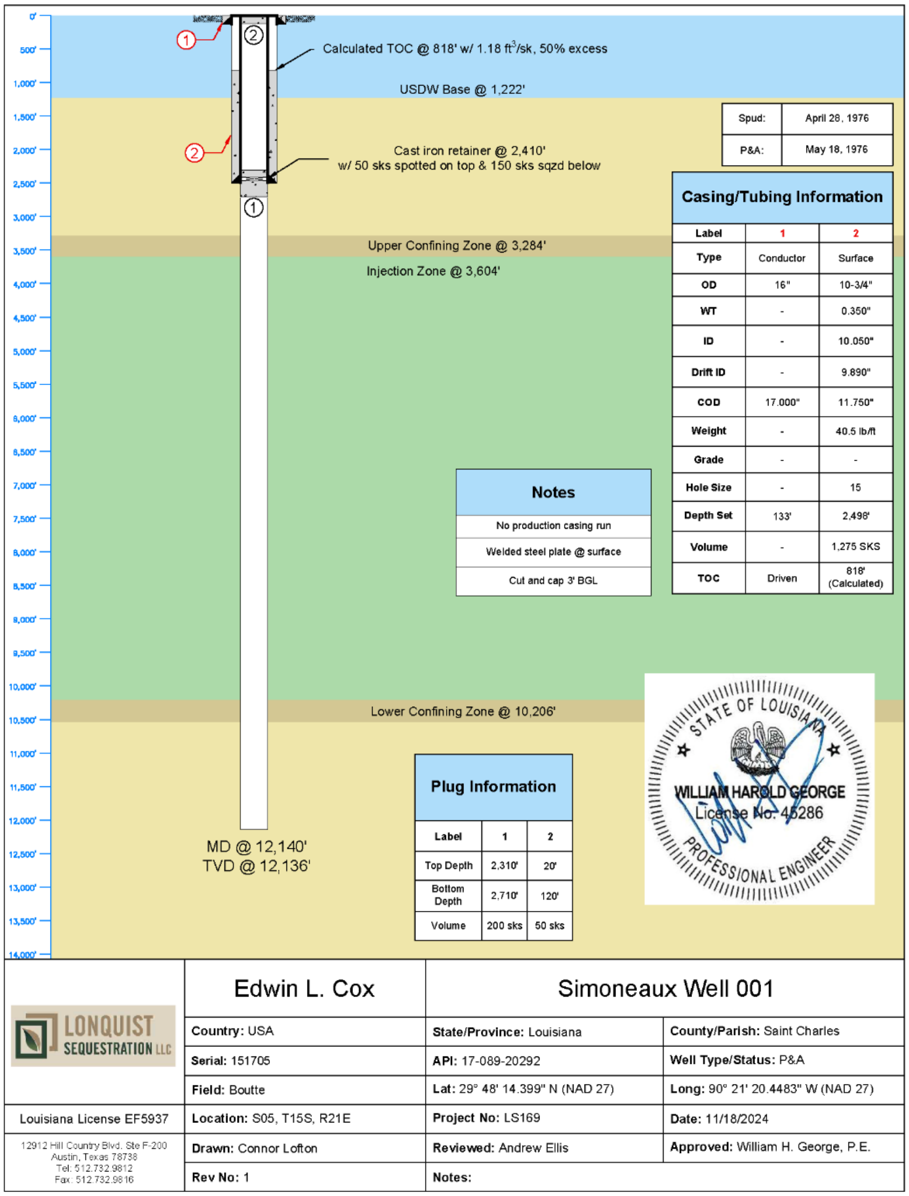
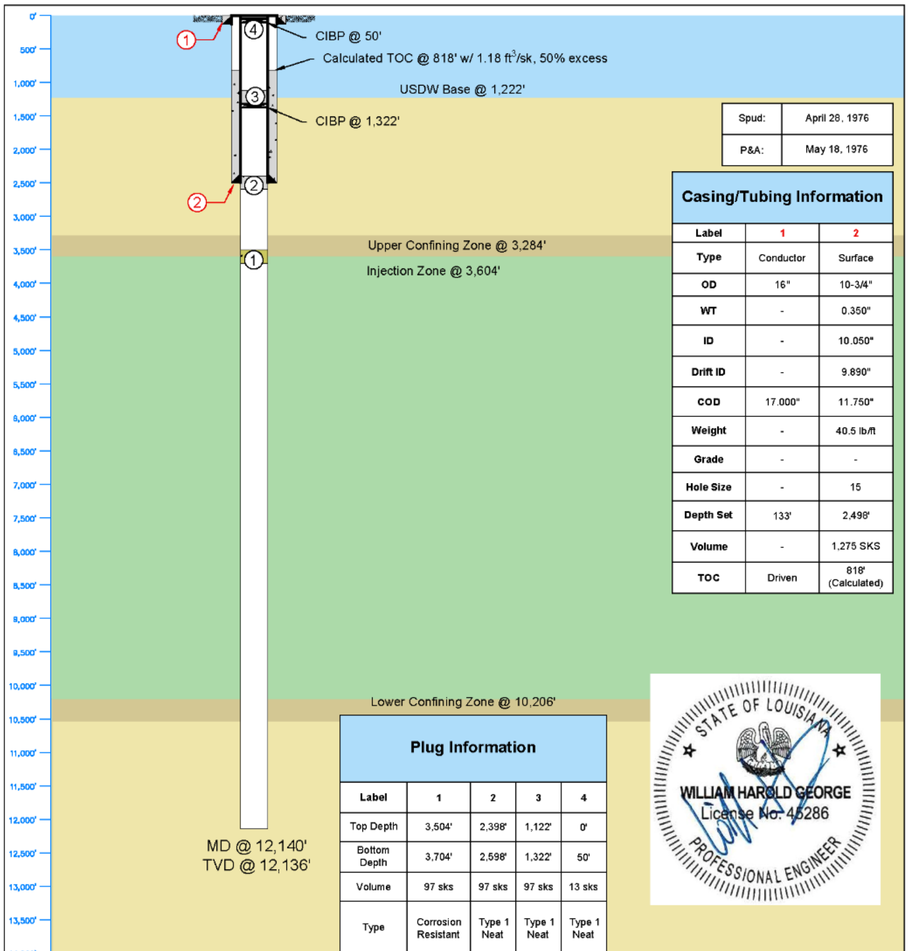


Figure 3-23 – Simoneaux No. 01 (SN 151705) Current State Schematic



Spud:	April 28, 1976
P&A:	May 18, 1976

Casing/Tubing Information

Label	1	2
Type	Conductor	Surface
OD	16"	10-3/4"
WT	-	0.350"
ID	-	10.050"
Drift ID	-	9.890"
COD	17.000"	11.750"
Weight	-	40.5 lb/ft
Grade	-	-
Hole Size	-	15
Depth Set	133'	2,498'
Volume	-	1,275 SKS
TOC	Driven	818' (Calculated)

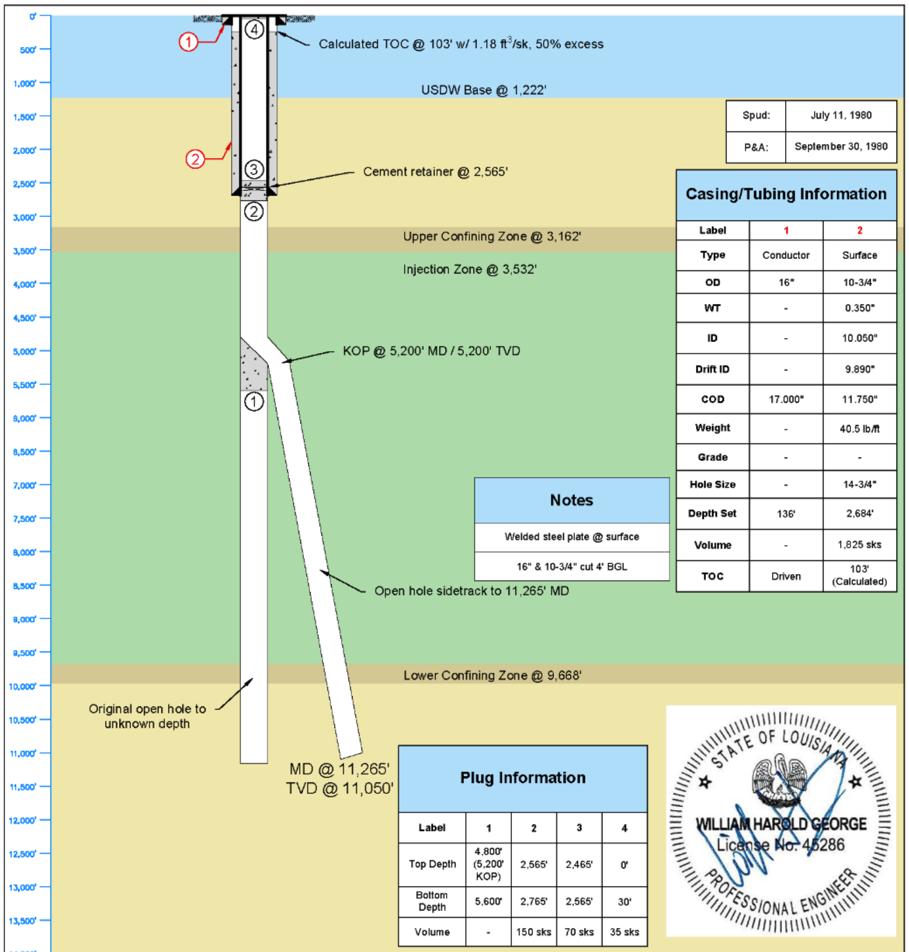
Plug Information

Label	1	2	3	4
Top Depth	3,504'	2,398'	1,122'	0'
Bottom Depth	3,704'	2,598'	1,322'	50'
Volume	97 sks	97 sks	97 sks	13 sks
Type	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 151705	**API:** 17-089-20292	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 48' 14.399" N (NAD 27)	**Long:** 90° 21' 20.4483" W (NAD 27)
Louisiana License EF5937	**Location:** S05, T15S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-24 – Simoneaux No. 01 (SN 151705) Corrective Action Schematic

Well Name: L B Simoneaux ET AL No. 01
Serial Number: 168952
API Number: 17-089-20413



Spud:	July 11, 1980
P&A:	September 30, 1980

Casing/Tubing Information

Label	1	2
Type	Conductor	Surface
OD	16"	10-3/4"
WT	-	0.350"
ID	-	10.050"
Drift ID	-	9.890"
COD	17.000"	11.750"
Weight	-	40.5 lb/ft
Grade	-	-
Hole Size	-	14-3/4"
Depth Set	136'	2,684'
Volume	-	1,825 sks
TOC	Driven	103' (Calculated)

Notes

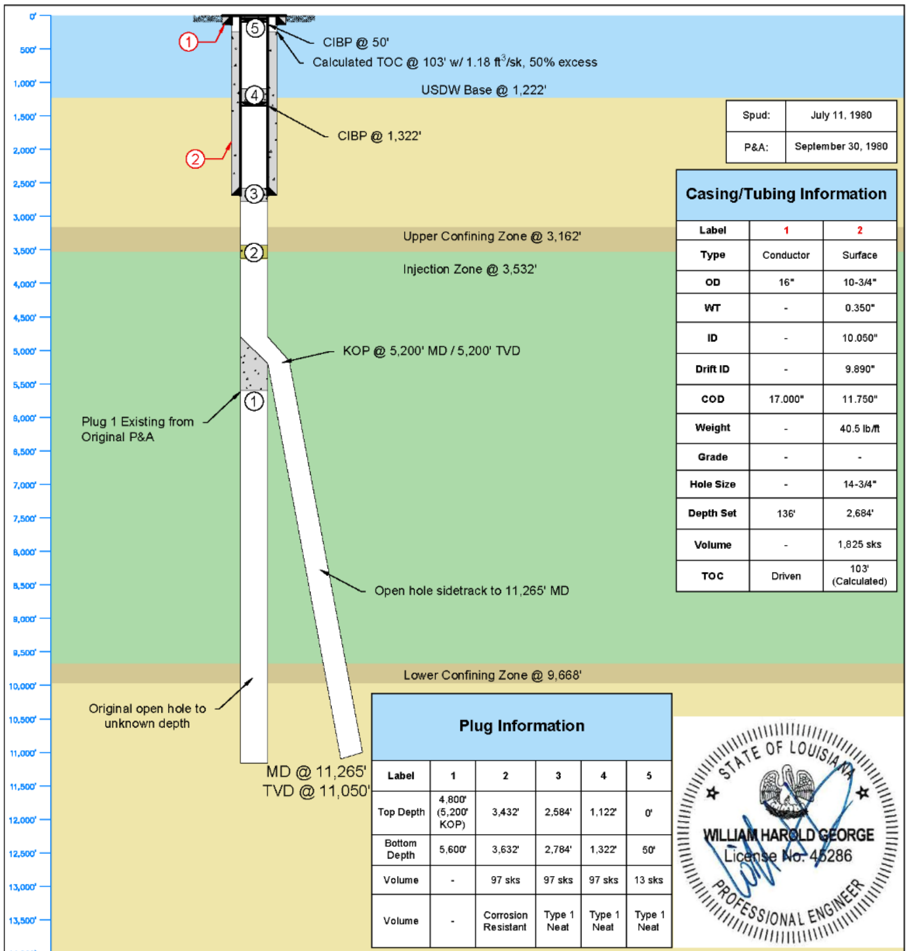
Notes
Welded steel plate @ surface
16" & 10-3/4" cut 4' BGL

Plug Information

Label	1	2	3	4
Top Depth	4,800' (5,200' KOP)	2,565'	2,465'	0'
Bottom Depth	5,600'	2,765'	2,565'	30'
Volume	-	150 sks	70 sks	35 sks

LONQUIST SEQUESTRATION LLC	Inexco Oil Company	L B SIMONEAUX ET AL Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 168952	**API:** 17-089-20413	**Well Type/Status:** P&A
	Field: Wildcat	**Lat:** 29° 49' 30.633" N	**Long:** 90° 21' 30.7362" W
Louisiana License EF5937	**Location:** S29, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-25 – L B Simoneaux ET AL No. 01 (SN 168952) Current State Schematic



Spud:	July 11, 1980
P&A:	September 30, 1980

Casing/Tubing Information

Label	1	2
Type	Conductor	Surface
OD	16"	10-3/4"
WT	-	0.350"
ID	-	10.050"
Drift ID	-	9.890"
COD	17.000"	11.750"
Weight	-	40.5 lb/ft
Grade	-	-
Hole Size	-	14-3/4"
Depth Set	136'	2,684'
Volume	-	1,825 sks
TOC	Driven	103' (Calculated)

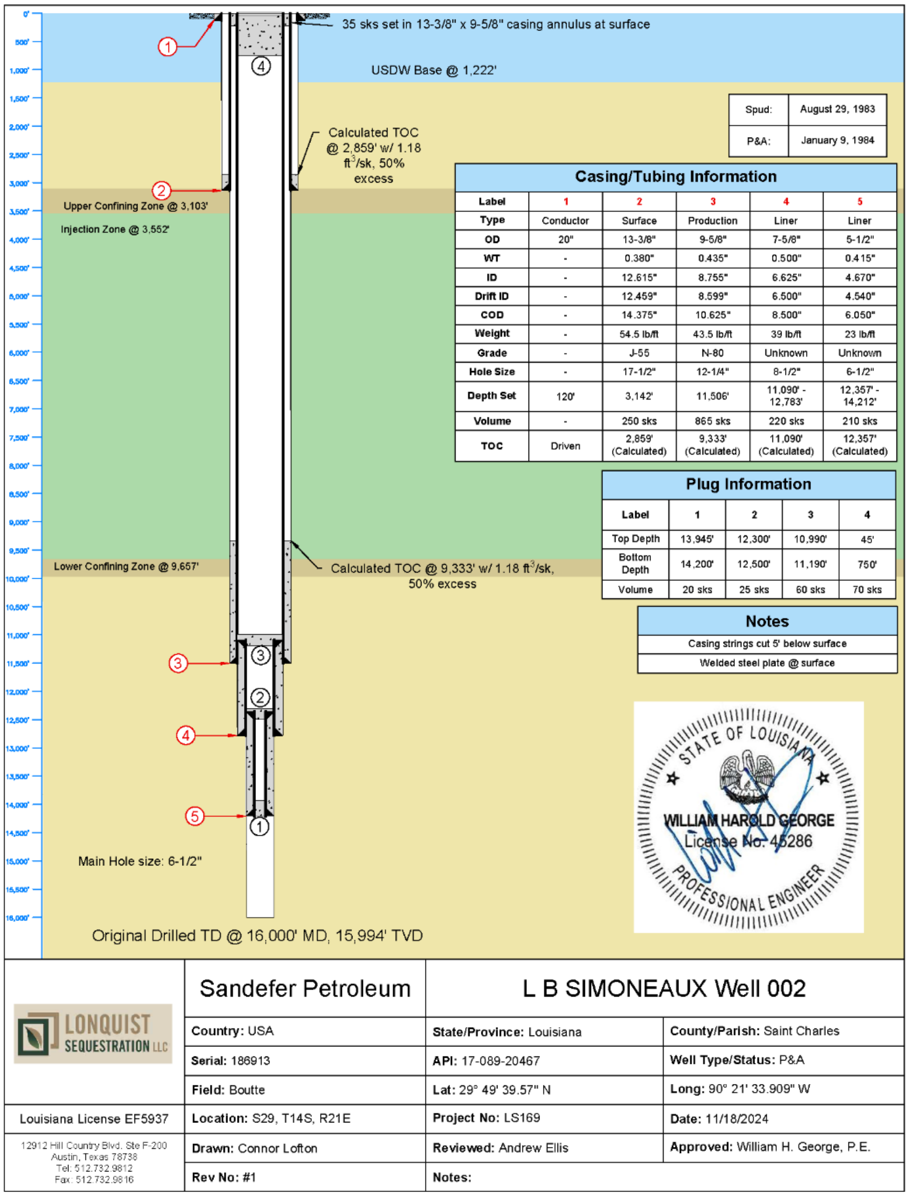
Plug Information

Label	1	2	3	4	5
Top Depth	4,800' (5,200' KOP)	3,432'	2,584'	1,122'	0'
Bottom Depth	5,600'	3,632'	2,784'	1,322'	50'
Volume	-	97 sks	97 sks	97 sks	13 sks
Volume	-	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	L B SIMONEAUX ET AL Well 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 168952	**API:** 17-089-20413	**Well Type/Status:** P&A
	Field: Wildcat	**Lat:** 29° 49' 30.633" N	**Long:** 90° 21' 30.7362" W
Louisiana License EF5937	**Location:** S29, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 3-26– L B Simoneaux ET AL No. 01 (SN 168952) Corrective Action Schematic

Well Name: L B Simoneaux No. 02
Serial Number: 186913
API Number: 17-089-20467



Spud:	August 29, 1983
P&A:	January 9, 1984

Casing/Tubing Information

Label	1	2	3	4	5
Type	Conductor	Surface	Production	Liner	Liner
OD	20"	13-3/8"	9-5/8"	7-5/8"	5-1/2"
WT	-	0.380"	0.435"	0.500"	0.415"
ID	-	12.615"	8.755"	6.625"	4.670"
Drift ID	-	12.459"	8.599"	6.500"	4.540"
COD	-	14.375"	10.625"	8.500"	6.050"
Weight	-	54.5 lb/ft	43.5 lb/ft	39 lb/ft	23 lb/ft
Grade	-	J-55	N-80	Unknown	Unknown
Hole Size	-	17-1/2"	12-1/4"	8-1/2"	6-1/2"
Depth Set	120'	3,142'	11,506'	11,090' - 12,783'	12,357' - 14,212'
Volume	-	250 sks	865 sks	220 sks	210 sks
TOC	Driven	2,859' (Calculated)	9,333' (Calculated)	11,090' (Calculated)	12,357' (Calculated)

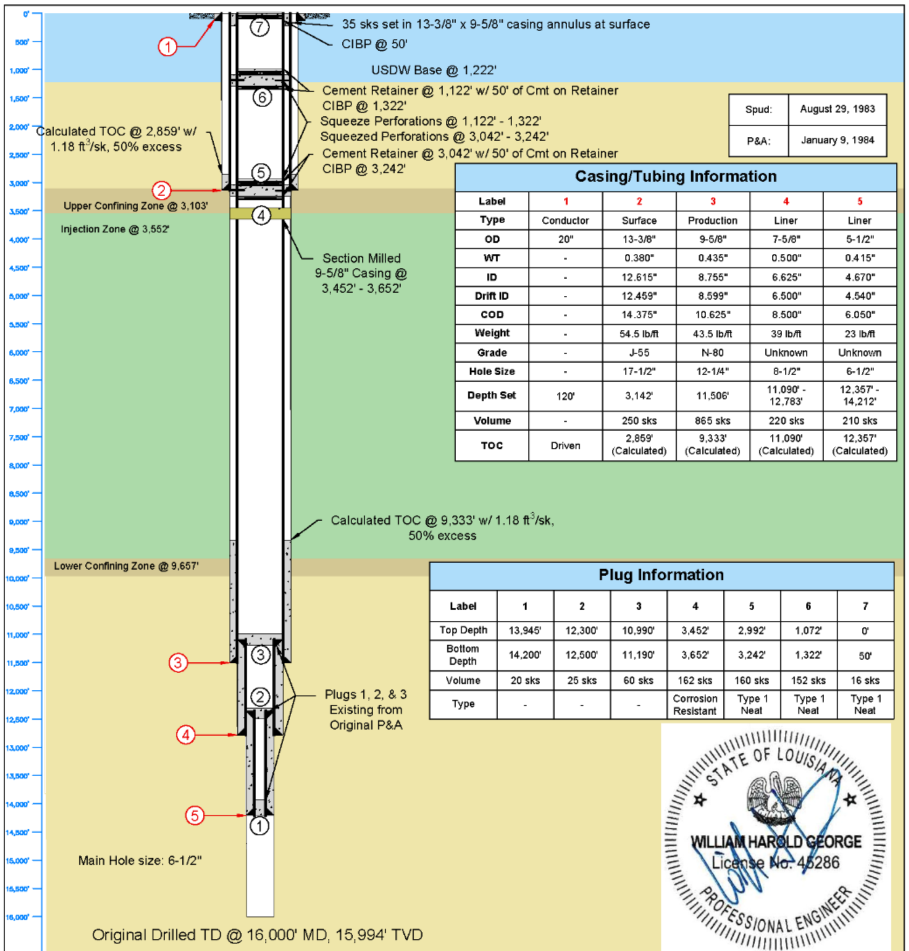
Plug Information

Label	1	2	3	4
Top Depth	13,945'	12,300'	10,990'	45'
Bottom Depth	14,200'	12,500'	11,190'	750'
Volume	20 sks	25 sks	60 sks	70 sks

Notes

Casing strings cut 5' below surface
Welded steel plate @ surface

Figure 3-27 – L B Simoneaux No. 02 (SN 186913) Current State Schematic



Spud:	August 29, 1983
P&A:	January 9, 1984

Casing/Tubing Information

Label	1	2	3	4	5
Type	Conductor	Surface	Production	Liner	Liner
OD	20"	13-3/8"	9-5/8"	7-5/8"	5-1/2"
WT	-	0.380"	0.435"	0.500"	0.415"
ID	-	12.615"	8.755"	6.625"	4.670"
Drift ID	-	12.459"	8.599"	6.500"	4.540"
COD	-	14.375"	10.625"	8.500"	6.050"
Weight	-	54.5 lb/ft	43.5 lb/ft	39 lb/ft	23 lb/ft
Grade	-	J-55	N-80	Unknown	Unknown
Hole Size	-	17-1/2"	12-1/4"	8-1/2"	6-1/2"
Depth Set	120'	3,142'	11,506'	11,090' - 12,783'	12,357' - 14,212'
Volume	-	250 sks	865 sks	220 sks	210 sks
TOC	Driven	2,859' (Calculated)	9,333' (Calculated)	11,090' (Calculated)	12,357' (Calculated)

Plug Information

Label	1	2	3	4	5	6	7
Top Depth	13,945'	12,300'	10,990'	3,452'	2,992'	1,072'	0'
Bottom Depth	14,200'	12,500'	11,190'	3,652'	3,242'	1,322'	50'
Volume	20 sks	25 sks	60 sks	162 sks	160 sks	152 sks	16 sks
Type	-	-	-	Corrosion Resistant	Type 1 Neat	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	L B SIMONEAUX Well 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** Saint Charles
	Serial: 186913	**API:** 17-089-20467	**Well Type/Status:** P&A
	Field: Boutte	**Lat:** 29° 49' 39.57" N	**Long:** 90° 21' 33.909" W
Louisiana License EF5937	**Location:** S29, T14S, R21E	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: #1	**Notes:**	

Figure 3-28 – L B Simoneaux No. 02 (SN 186913) Corrective Action Schematic

3.5 Area of Review Reevaluation Plan and Schedule

3.5.1 Proposed Reevaluation Cycle

The AOR reevaluation plan (as shown in Table 3-7) will be evaluated at least once every 5 years or after one of the events listed in table triggers a reevaluation of the AOR. All data used to support the AOR reevaluations will be retained for 10 years.

Table 3-7 – Triggers for AOR Reevaluations

Reevaluation Trigger	Measure to Be Taken
SWO 29-N-6 **§3615.B.2.b.i** [40 CFR **146.84(b)(2)(i)**]	Reevaluate the AOR as required by statute.
Annual plume migration survey identifies a materially greater extent than modeled.	Rerun the reservoir plume model with new data. Reevaluate the AOR.
Annual plume migration survey identifies that the plume direction is materially different than modeled.	Rerun the reservoir plume model with new data. Reevaluate the AOR.
Operational Change: Continuous monitoring systems determine that an injection operating parameter (such as total volume) has been exceeded.	Rerun the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.
Operational Change: Injectate composition changes to a new mixture, outside of injectate specifications.	Rerun the reservoir plume model with new data. If plume extents increase, reevaluate the AOR.
Additional site characterization information that will provide additional information.	Rerun the reservoir plume model with new data. If the plume increases in extents, reevaluate the AOR.
New operations are being brought online within or near the plume extents, within the injection interval.	Rerun the reservoir plume model with new data. If the plume increases in shape or extents, reevaluate the AOR.
Seismic event with a magnitude of 3 or higher within a 2-mile radius of the Libra project injection site or other emergency occurs.	Perform a plume migration survey. If the plume increases in shape or extents, reevaluate the AOR.

The following AOR maps and resultant tables are included in *Appendix C* in large-scale format for ease of detailed review.

Appendix C – AOR and Corrective Action:

- Appendix C-1 Oil and Gas Wells AOR Map

- Appendix C-2 Oil and Gas Wells AOR List
- Appendix C-3 Freshwater Wells AOR Map
- Appendix C-4 Freshwater Wells AOR List
- Appendix C-5 Site Review AOR Map
- Appendix C-6 Corrective Action Well Schematics and Procedures
- Appendix C-7 Schematics for Wells in the AOR that don't require Corrective Action

3.6 References

Davis, K.E. (1986). Factors affecting the area of review for hazardous waste disposal wells. Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Association, Dublin, Ohio, 148-194.

SECTION 4 – ENGINEERING DESIGN AND OPERATING STRATEGY

TABLE OF CONTENTS

Figures

Tables

4.1 Introduction

The following section provides the engineering design and well construction details, as well as the drilling and completion operational strategies, involved in the planning of the proposed Simoneaux CCS Injector Well No. 001, Simoneaux CCS Injector Well No. 002, and Simoneaux CCS Injector Well No. 003. The details of the engineering design satisfy all requirements of Statewide Order (SWO) 29-N-6 **§3617.A** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.86**.

The Class VI injection well designs, construction, and operation are governed by the Louisiana Department of Energy and Natural Resources (LDENR). All Class VI carbon capture and storage (CCS) projects are designed with the purpose of developing and implementing a safe method to sequester and store CO_2 within the allocated injection zone—and to ensure the containment to that zone for the protection of Underground Sources of Drinking Water (USDWs).

The Lapis Energy (LA Development), LP (Lapis) project will implement the designs and strategy included in this section to store CO_2 safely within the sandstone intervals of the Miocene injection zone. The reservoir characteristics of the injection zone offer ideal storage capacity and transmissibility for safely sequestering CO_2 for the life of the Libra CO_2 Storage Solutions (Libra) Project. The Miocene injection zone consists of sand packages exhibiting high porosity and permeability, and minimal existing oil-and-gas activity or well penetrations.

The specific requirements implemented for the design and operation of the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 are described in the following sections.

4.2 Engineering Design

The purpose in the engineering design of the proposed injection wells is to ensure isolation of the injectate to the injection zone and to protect the USDW from any contamination. Therefore, the planning of the well construction considers critical design parameters such as injection rates, injection volumes, fluid properties, bottom hole temperatures, bottom hole pressures, rock properties, and chemical properties of the injectate fluid.

The wellbore construction materials for the injection wells were selected for compatibility with the corrosive downhole conditions that result from the combination of CO_2 mixed with formation fluids. The corrosion-resistant components offer the ability to withstand extended exposure to the corrosive environment and prevent any migration of CO_2 from the injection zone. The design also considers the cement composition of the long string casing and includes products designed to provide a good bond between the casing and formation in the presence of corrosive fluids within the injection zone.

The Libra Project will sequester the injectate within the planned injection zone—the Miocene sands—and confine the injectate to the injection zone by upper and lower bounding shale zones, specifically the upper and lower confining zones. The completion strategy of the proposed injection wells involves an initial completion within a predefined subset of the Miocene sands and a plugback and recompletion of the wells into shallower Miocene sand sequences. The strategy offers additional aid in vertical migration through the localized sealing of sub-injection intervals by the intermittent shale layers. The top of the Miocene injection zone for the injection wells is located at approximately 3,504 feet (ft).

The Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 will each be constructed with surface casing set below the USDW and long string casing set in the Miocene injection zone. The wells will be drilled and completed at varying depths within the Miocene, with the deep injector, No. 001, completed in the lower Miocene interval; the middle injector, No. 002, completed in the middle portion of the Miocene interval; and the shallow injector, No. 003, completed in the upper Miocene interval. The completion strategy of the project will allow continuous injection within multiple intervals of the gross injection zone for the duration of the injection period.

Upon completion of each well, injection will commence within the Miocene sand intervals of the original completion stage, per the current model and as part of the completion plan. The tubing encapsulated conductor (TEC) lines will be installed on the backside of the injection tubing and connected to a ported sub with internal and external pressure gauges. These gauges provide the ability to monitor bottomhole pressure and temperature in real time. Additionally, the downhole monitoring equipment will be active for the life of the Libra Project to provide direct monitoring of the active completion stage. The extensive monitoring program is included in *Section 5 – Testing and Monitoring Plan.*

The completion strategy for the injection wells involves completing each well within a predefined interval of the gross Miocene injection zone. Each well will involve an original completion, where the lower portion of the Miocene sands of each wellbore is developed. Once the original completion interval is fully developed, each well will be recompleted by isolating the open perforations with an expandable plug and setting cement. The shallower portion of the Miocene sands for each well will be perforated, and the injection will continue until the second completion stage is fully developed. The operational strategy for each completion is shown in Tables 4-1 through 4-3 for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.

Table 4-1 – Simoneaux CCS Injector Well No. 001 Operational Strategy

Completion Stage	Top Perforation (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (Months)
1	9,187	637	390	120
2	8,168	822	448	120

Table 4-2 – Simoneaux CCS Injector Well No. 002 Operational Strategy

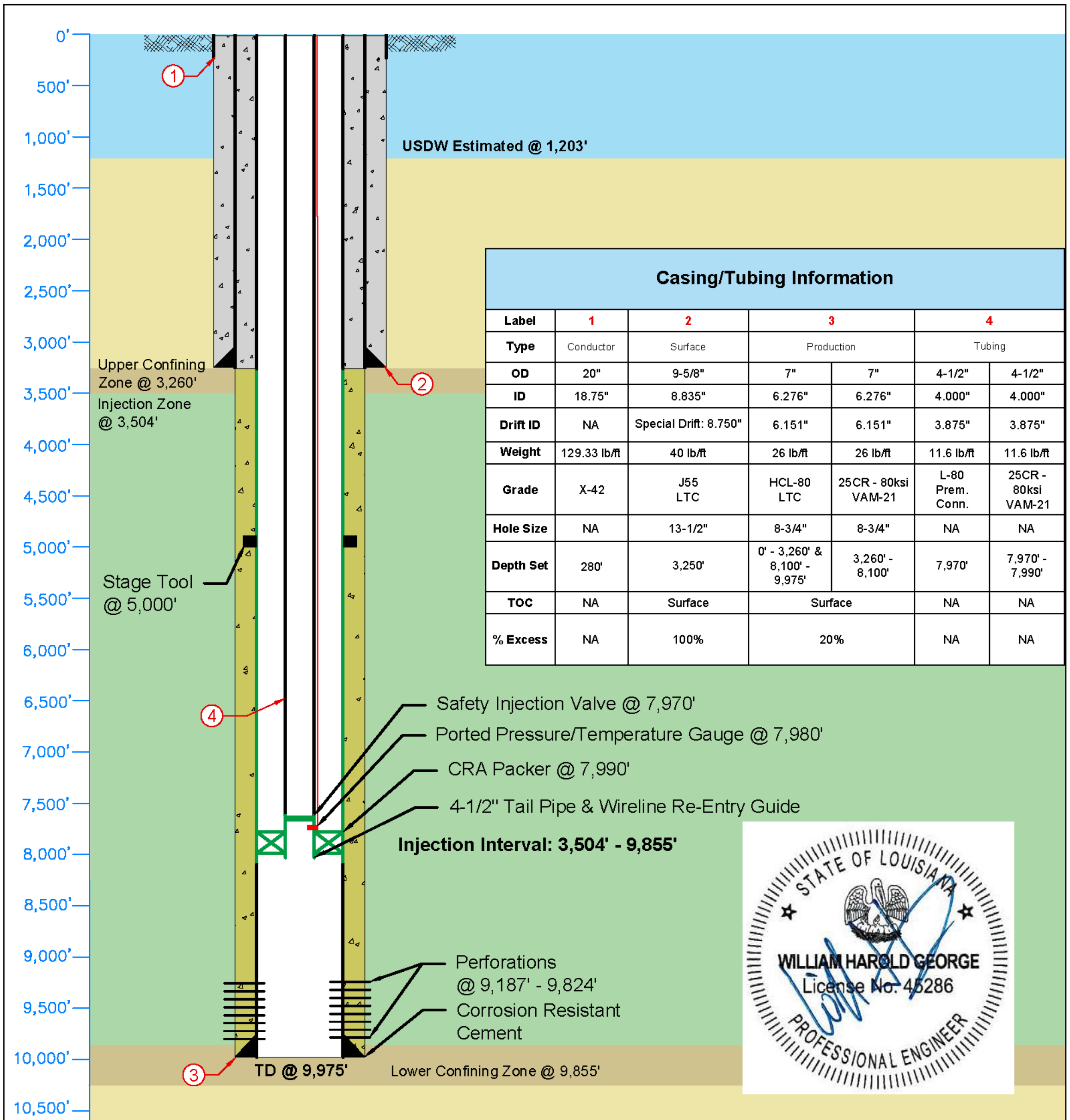
Completion Stage	Top Perforation (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (Months)
1	7,306	554	283	120
2	6,838	407	153	108

Table 4-3 – Simoneaux CCS Injector Well No. 003 Operational Strategy

Completion Stage	Top Perf (ft)	Gross Thickness (ft)	Net Pay (ft)	Duration (Months)
1	5,959	649	230	120
2	5,129	688	257	96

Details for the long string include a 7 inch (in.) HCL-80 casing from the surface to the top of the upper confining zone (UCZ), 7-in. 25CR-80 casing across the upper portion of the UCZ and predetermined intervals of the injection zone, and 7-in. HCL-80 set across the injection interval. The completion assembly incorporates a 4-1/2 in. L-80 tubing, 4-1/2 in. 25CR-80 tubing, profile nipple, safety injection valve, 7 in. x 4-1/2 in. corrosion-resistant alloy (CRA) injection packer set above the pre-determined injection zone interval for each well, and 4-1/2 in. 25CR-80 tail pipe with wireline reentry guide. The monitoring equipment will be installed on the backside of the tubing and include TEC, along with internal and externally mounted pressure gauges set above the injection packer. A table of depths for each completion stage is provided in Tables 4-38 through 4-40 (*Section 4.4*) for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively. The final well is designed in a way that the appropriate testing devices, down hole tools and equipment can be utilized to meet the needs of the project.

Figures 4-1 through 4-3 show the proposed wellbore designs for each injector, respectively.

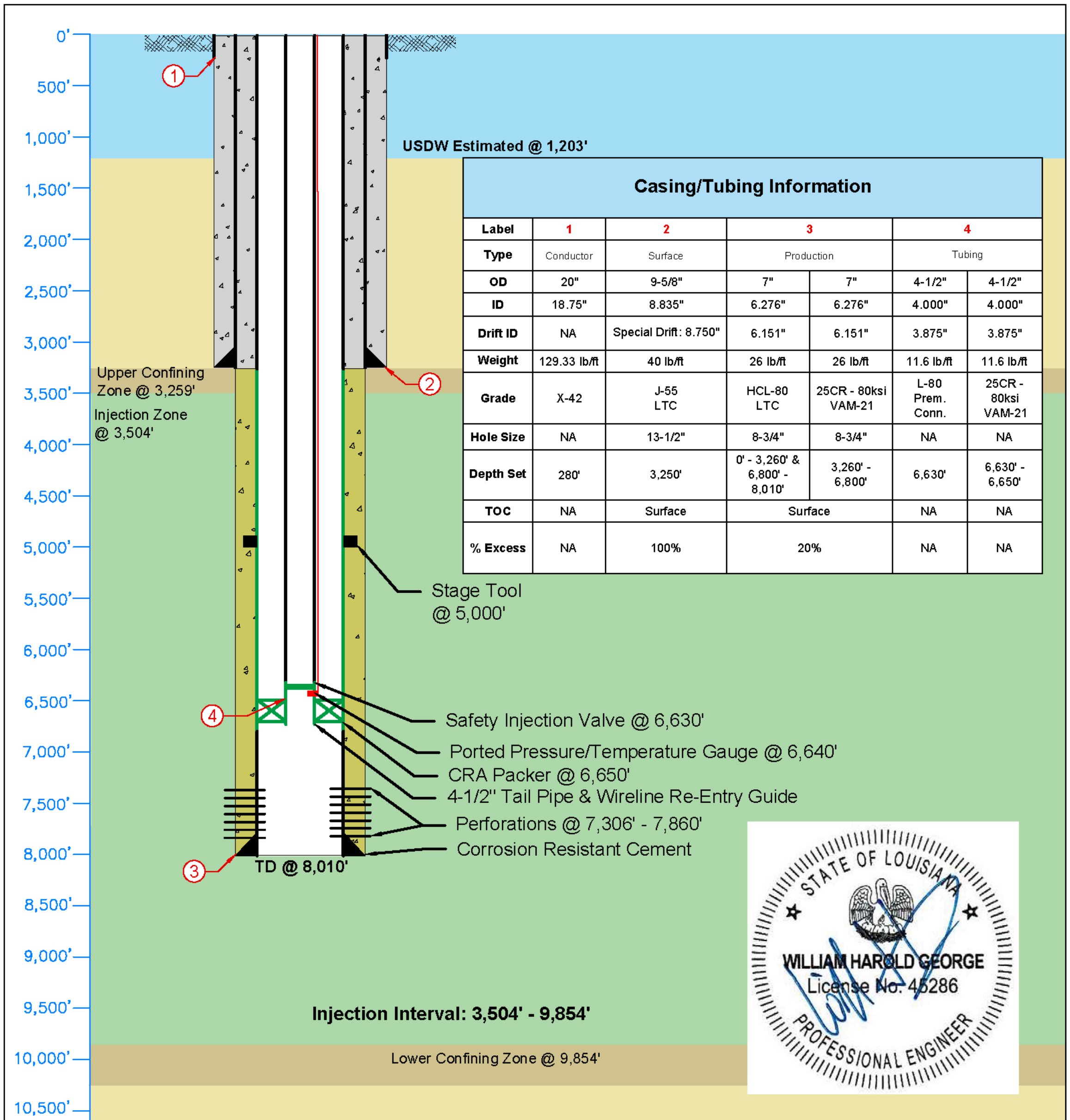


Casing/Tubing Information

Label	1	2	3	3	4	4
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'	7,970'	7,970' - 7,990'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.226" W, 29° 48' 35.315" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 4-1 – Simoneaux CCS Injector Well No. 001 Wellbore Schematic

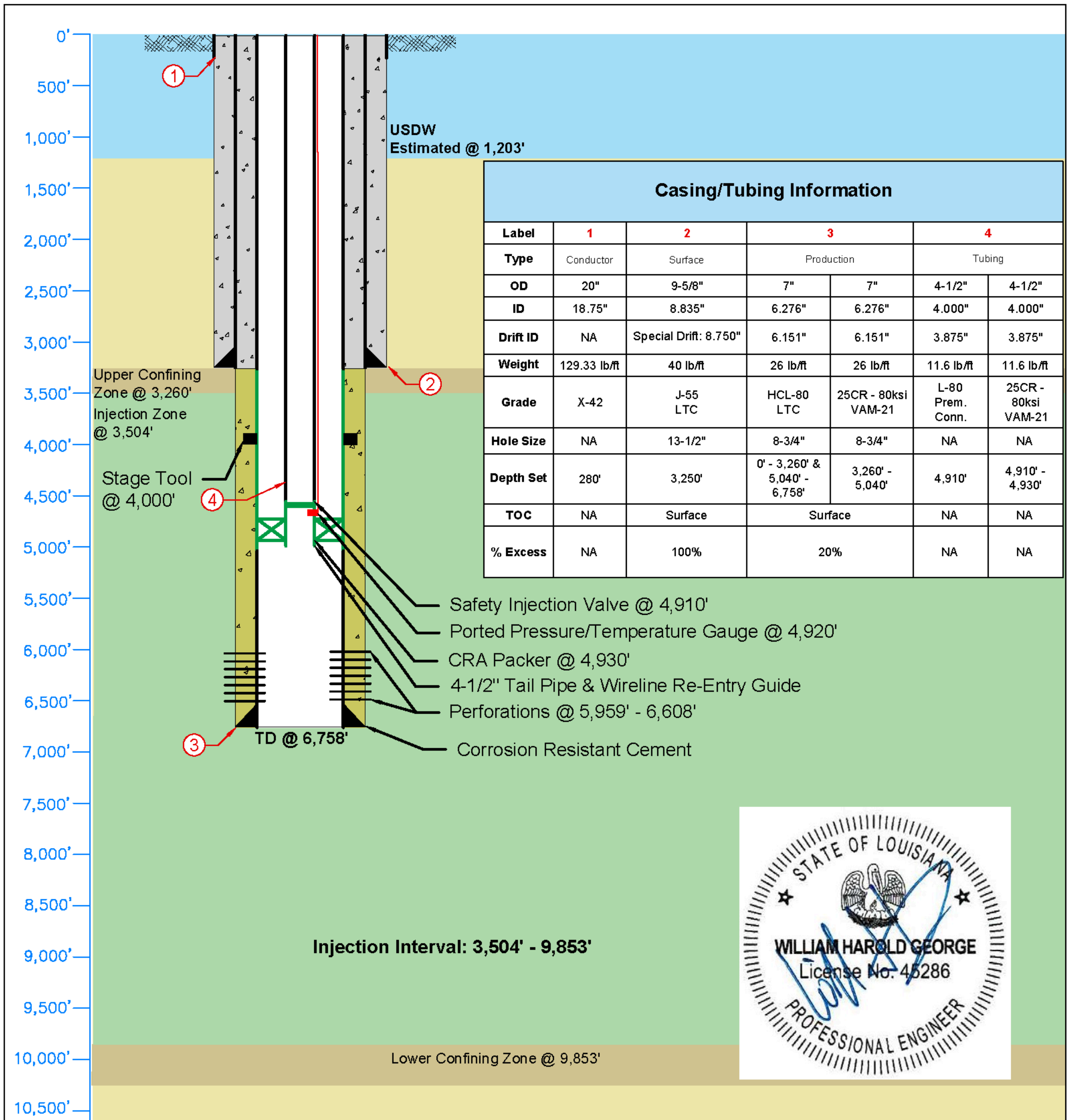


Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'	6,630'	6,630' - 6,650'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.510" W, 29° 48' 35.317" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 4-2 – Simoneaux CCS Injector Well No. 002 Wellbore Schematic



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'	4,910'	4,910' - 4,930'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.793 W, 29° 48' 35.319" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 4-3 – Simoneaux CCS Injector Well No. 003 Wellbore Schematic

The drilling and completion design for Simoneaux CCS Injector Well No. 001 is as follows:

- Conductor Pipe
  - 20 in. to +/- 280 ft (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of openhole logging during the drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is 3,250 ft true vertical depth (TVD).
  - 13-1/2 in. hole size
  - 9-5/8 in. outer diameter (OD) casing
  - Cemented to surface
- Long String Casing
  - 8-3/4 in. hole size
  - 7-in. casing set to total depth (TD) of the well
    - 7-in. casing above the UCZ will be HCL-80, LTC.
      - 7-in. casing from surface to 3,260 ft
    - 7-in. casing across the UCZ and upper portion of the injection zone will be 25CR SDSS-80, premium connections.
      - 7-in. casing from 3,260 to 8,100 ft
    - 7-in. casing across the lower portion of the injection zone will be HCL-80, LTC.
      - 7-in. casing from 8,100 ft to 9,975 ft
  - Cemented to surface
    - Cement to be comprised of:
      - Corrosion-resistant cement across the UCZ, designed to be from 9,975 ft to 3,250 ft
      - Blended Portland cement from 3,250 ft to surface
- Completion Assembly
  - 4-1/2 in. tubing from surface to 7,970 ft will be L-80, premium connections.
  - 4-1/2 in. tubing and profile nipple from 7,970 ft to 7,990 ft, will be 25CR SDSS-80.
  - Injection valve at 7,970 ft
    - 25CR SDSS or equivalent
  - 7- in. x 4-1/2 in. injection packer at 7,990 ft
    - 25CR SDSS or equivalent
  - 4-1/2 in. tail pipe from 7,990 ft to 8,000 ft will be 25CR SDSS-80.
  - Per metallurgical analysis, minimum recommendations are as follows:
    - L-80 tubing above the packer safety injection valve
    - 25CR SDSS tubulars and equipment across the UCZ
  - Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
  - Casing head assembly
    - 9-5/8 in. slip-on weld (SOW) x 11 in. 5M (BB trim)

            - 2-1/16 in. 5M manual gate side-outlet valve
        - 11 in. nominal (NOM) x 7 in. hanger
    - Tubing spool assembly
        - 11 in. 5M in. x 7-1/16 in. 5M tubing spool (CC trim)
            - 2-1/16 in. 5M manual gate side-outlet valves
    - Production tree assembly
        - 7-1/16 in. NOM x 4-1/2 in. mandrel hanger (CC trim)
        - 7-1/16 in. 5M x 4-1/16 in. 5M adapter flange (CC trim)
        - 4-1/16 in. 5M manual gate lower-master valve (CC trim)
        - 4-1/16 in. 5M manual gate upper-master valve (CC trim)
        - 4-1/16 in. 5M cap flange (CC trim)

The drilling and completion design for Simoneaux CCS Injector Well No. 002 is as follows:

- Conductor Pipe
    - 20 in. to +/- 280 ft (or 200 blows/ft)
- Surface Casing
    - To be set below the lowermost USDW
        - The USDW will be determined by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
        - The current estimated setting depth is 3,250 ft TVD.
    - 13-1/2 in. hole size
    - 9-5/8 in. OD casing
    - Cemented to surface
- Long String Casing
    - 8-3/4 in. hole size
    - 7-in. casing set to TD of well
        - 7-in. casing above the UCZ will be HCL-80, LTC.
            - 7-in. casing from surface to 3,260 ft
        - 7-in. casing across the UCZ and upper portion of the injection zone will be 25CR SDSS-80, premium connections.
            - 7-in. casing from 3,260 ft to 6,800 ft
        - 7-in. casing across the lower portion of the injection zone will be HCL-80, LTC.
            - 7-in. casing from 6,800 ft to 8,010 ft
    - Cemented to surface
        - Cement to be comprised of:
            - Corrosion-resistant cement across the UCZ, designed to be from 8,010 ft to 3,250 ft
- Blended Portland cement from 3,250 ft to surface
- Completion Assembly
    - 4-1/2 in. tubing from surface to 6,630 ft will be L-80, premium connections.
    - 4-1/2 in. tubing and profile nipple from 6,630 ft to 6,650 ft will be 25CR SDSS-80.

- Injection valve at 6,630 ft
  - 25CR SDSS or equivalent
- 7- in. x 4-1/2 in. injection packer at 6,650 ft
  - 25CR SDSS or equivalent
- 4-1/2 in. tail pipe from 6,650 ft to 6,660 ft will be 25CR SDSS-80.
- Per metallurgical analysis, minimum recommendations are as follows:
  - L-80 tubing above the packer safety injection valve
  - 25CR SDSS tubulars and equipment across the UCZ
- Tubing annulus will be filled with a noncorrosive fluid.

- Wellhead
  - Casing head assembly
    - 9-5/8 in. SOW x 11 in. 5M (BB trim)
      - 2-1/16 in. 5M manual gate side-outlet valve
    - 11 in. NOM x 7 in. hanger
  - Tubing spool assembly
    - 11 in. 5M in. x 7-1/16 in. 5M tubing spool (CC trim)
      - 2-1/16 in. 5M manual gate side-outlet valves
  - Production tree assembly
    - 7-1/16 in. NOM x 4-1/2 in. mandrel hanger (CC trim)
    - 7-1/16 in. 5M x 4-1/16 in. 5M adapter flange (CC trim)
    - 4-1/16 in. 5M manual gate lower-master valve (CC trim)
    - 4-1/16 in. 5M manual gate upper-master valve (CC trim)
    - 4-1/16 in. 5M cap flange (CC trim)

The drilling and completion design for the Simoneaux CCS Injector No. 003 is as follows:

- Conductor Pipe
  - 20 in. to +/- 280 ft (or 200 blows/ft)
- Surface Casing
  - To be set below the lowermost USDW
    - The USDW will be determined by means of openhole logging during drilling of the well. If necessary, the final setting depth will be adjusted.
    - The current estimated setting depth is 3,250 ft TVD.
  - 13-1/2 in. hole size
  - 9-5/8 in. OD casing
  - Cemented to surface
- Long String Casing
  - 8-3/4 in. hole size
  - 7-in. casing set to TD of well
    - 7-in. casing above the UCZ will be HCL-80, LTC.
      - 7-in. casing from surface to 3,260 ft
    - 7-in. casing across the UCZ and upper portion of the injection zone will be 25CR SDSS-80, premium connections.

- 7-in. casing from 3,260 ft to 5,040 ft
    - 7-in. casing across the lower portion of the injection zone will be HCL-80, LTC.
      - 7-in. casing from 5,040 ft to 6,758 ft
  - Cemented to surface
    - Cement to be comprised of:
      - Corrosion-resistant cement across the UCZ, designed to be from 6,758 ft to 3,250 ft
      - Blended Portland cement from 3,250 ft to surface
- Completion Assembly
  - 4-1/2 in. tubing from surface to 4,910 ft will be L-80, premium connections.
  - 4-1/2 in. tubing and profile nipple from 4,910 ft to 4,930 ft will be 25CR SDSS-80.
  - Injection valve at 4,910 ft
    - 25CR SDSS or equivalent
  - 7- in. x 4-1/2 in. injection packer at 4,930 ft
    - 25CR SDSS or equivalent
  - 4-1/2 in. tail pipe from 4,930 ft to 4,940 ft will be 25CR-80 SDSS.
  - Per metallurgical analysis, minimum recommendations are as follows:
    - L-80 tubing above the packer safety injection valve
    - 25CR SDSS tubulars and equipment across the UCZ
  - Tubing annulus will be filled with a noncorrosive fluid.
- Wellhead
  - Casing head assembly
    - 9-5/8 in. SOW x 11 in. 5M (BB trim)
      - 2-1/16 in. 5M manual gate side-outlet valve
    - 11 in. NOM x 7 in. hanger
  - Tubing spool assembly
    - 11 in. 5M in. x 7-1/16 in. 5M tubing spool (CC trim)
      - 2-1/16 in. 5M manual gate side-outlet valves
  - Production tree assembly
    - 7-1/16 in. NOM x 4-1/2-in. mandrel hanger (CC trim)
    - 7-1/16 in. 5M x 4-1/16 in. 5M adapter flange (CC trim)
    - 4-1/16 in. 5M manual gate lower-master valve (CC trim)
    - 4-1/16 in. 5M manual gate upper-master valve (CC trim)
    - 4-1/16 in. 5M cap flange (CC trim)

A detailed drilling-and-completion prognosis is included in *Appendix D*.

4.2.1 Detailed Discussion of Injection Well Design

The Libra Project is designed to inject a maximum volume of CO_2 injectate of 4 million metric tons per year (MMT/yr) into the sand intervals of the proposed injection zones. This volume translates into a rate of 207.16 million standard cubic feet per day (MMscf/D), at standard conditions. The properties of the injectate, injection rate, and injection pressure were derived from reservoir modeling and incorporated in the engineering design of the injection wells when selecting weight and grades of the long string and tubing casing specifications. Table 4-4 shows the standard conditions of CO_2 used in the modeling and flow calculations.

Table 4-4 – Estimated CO_2 Pipeline Conditions

Temperature (°F)	Pressure (psia)	Density (lbmol/ft^3)	Enthalpy (Btu/lbmol)	Entropy (Btu/lbmol-°F)
85	2,513	1.187	-4,504	-16.122

*psia – pounds per square inch absolute
lbmol – pound mol
ft^3 – cubic foot

In the design of the proposed injection wells, a sensitivity analysis was run for the tubing specifications that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. The outputs of the reservoir-engineering model runs were used to generate the bottomhole pressures (BHPs), as shown in Figures 4-4 through 4-6 for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively. The model outputs identified when maximum BHP will occur during the life of the project and what the resulting maximum flowing pressure will be at the surface—and were incorporated for selecting the proper design of the casing, tubing, and wellhead configurations.

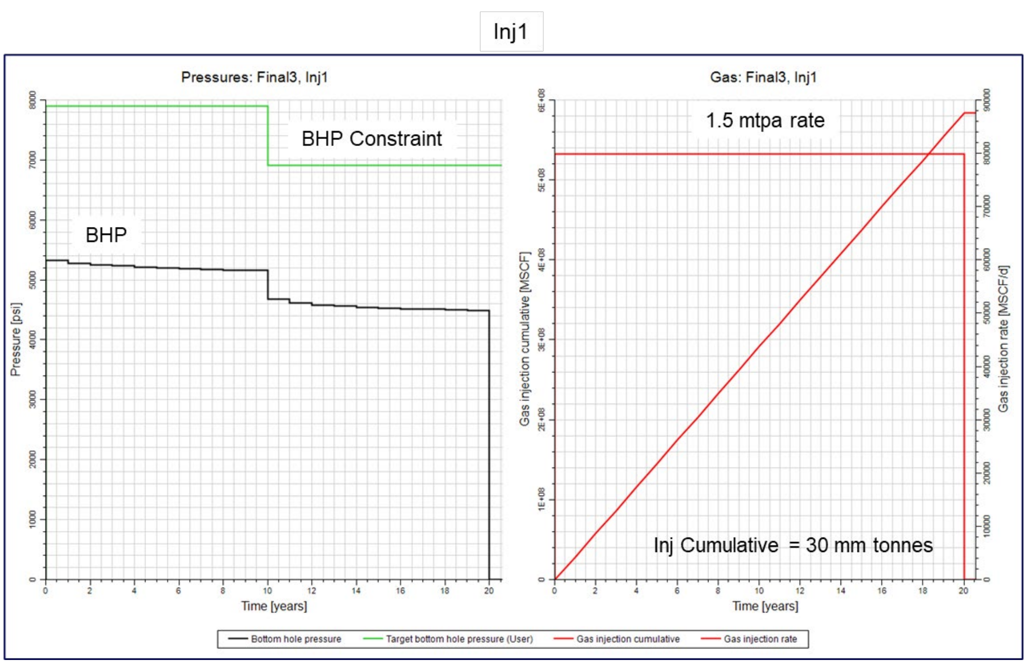


Figure 4-4 – Injection Pressure Plot for Simoneaux CCS Injector Well No. 001

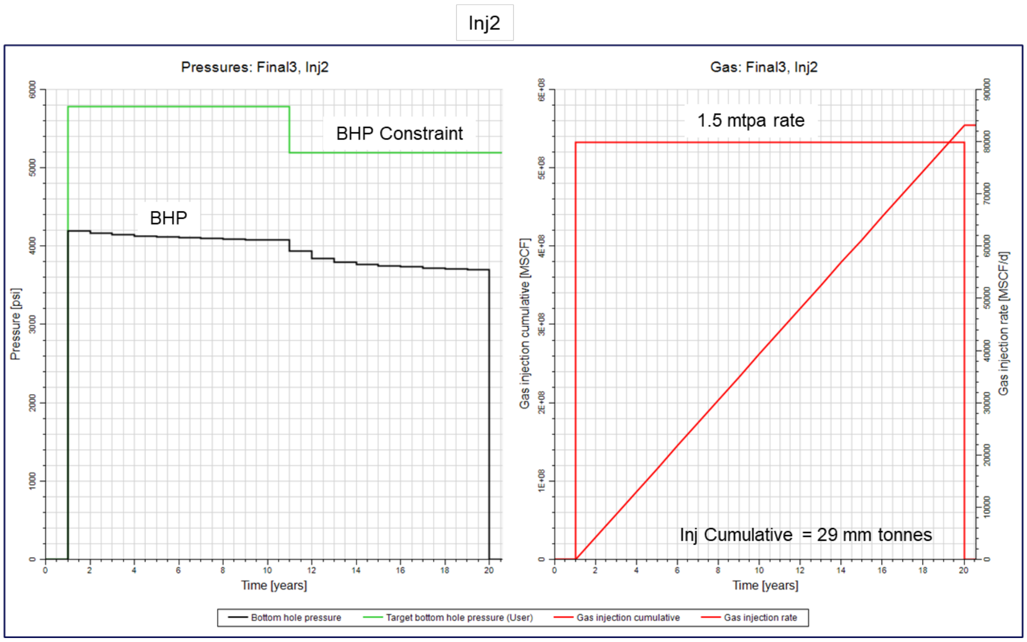


Figure 4-5 – Injection Pressure Plot for Simoneaux CCS Injector Well No. 002

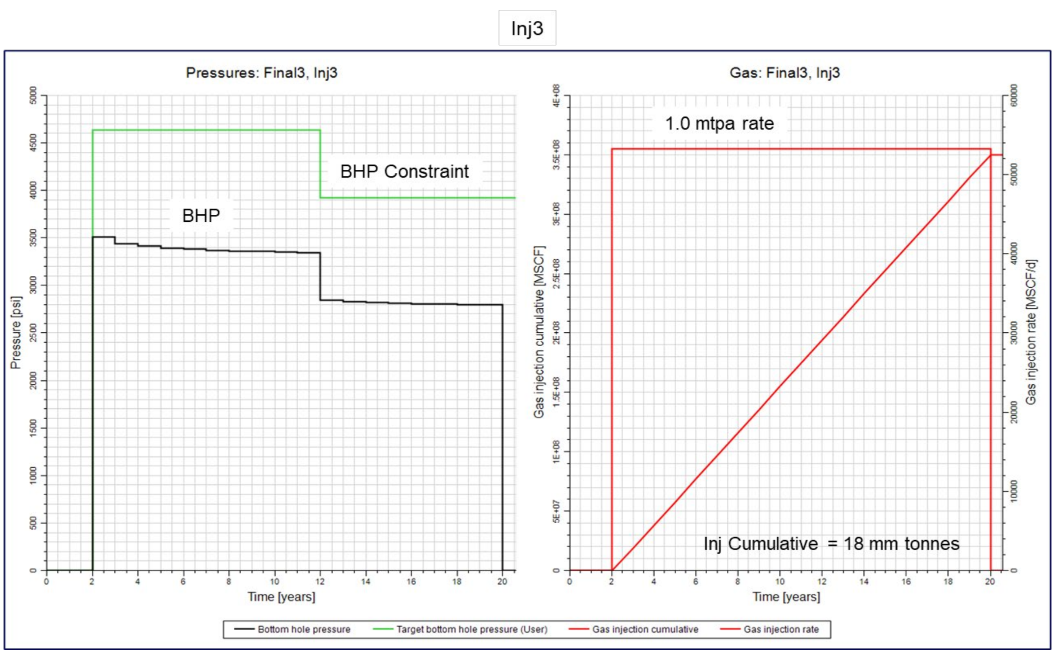


Figure 4-6 – Injection Pressure Plot for Simoneaux CCS Injector Well No. 003

For the reservoir model, a 100% CO_2 injectate stream was applied at an injection rate of 1.5–4.0 MMT/yr.

The input injection parameters from the model for each injection well are shown in Table 4-5. The calculated injection parameters are then shown in Tables 4-6 through 4-8 for the three injectors, respectively.

Table 4-5 – Input Injection Parameters for Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Inputs	No. 001	No. 002	No. 003
Maximum Injection Rate (MMT/yr)	1.5	1.5	1.0
Pressure Constraint Gradient (psi/ft)	0.66 – 0.79		
Injection Duration (yrs)	20	19	18
4 ½ in. Tubing Inner Diameter (ID) (in.)	3.75		
Absolute Roughness Factor	0.000591		
Wellhead Temperature (°F)	122		

*psi/ft – pounds per square inch per foot

Table 4-6 – Calculated Injection Parameters for Simoneaux CCS Injector Well No. 001

Stage	Date	Max Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)
1	1/1/2027	1.5	4,818	4,715	2,520
2	1/1/2037	1.5	4,470	4,346	2,532

*WHP – wellhead pressure

Table 4-7 – Calculated Injection Parameters for Simoneaux CCS Injector Well No. 002

Stage	Date	Max Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)
1	1/1/2028	1.5	3,901	3,832	2,213
2	1/1/2038	1.5	3,834	3,675	2,288

Table 4-8 – Calculated Injection Parameters for Simoneaux CCS Injector Well No. 003

Stage	Date	Max Rate (MMT/yr)	Max BHP (psi)	Avg BHP (psi)	Max WHP (psi)
1	1/1/2029	1.0	3,046	2,949	1,374
2	1/1/2039	1.0	2,666	2,635	1,292

The completion of the proposed injection wells includes a 4-1/2 in. injection string—based on the model and tubing design—which is the appropriate size to move the desired volumes of the supercritical CO_2 into the well and formation.

The casing sizes were selected for the appropriate bit size, pipe-clearance requirements, and recommended annular spacing for assurance of proper cementing, which includes the following:

- 20-in. conductor pipe
- 9-5/8 in. surface casing
- 7-in. long string casing
- 4-1/2 in. tubing

4.2.1.1 Conductor Pipe

Based on the loose, unconsolidated nature of the sediment near the surface, a conductor pipe will be installed to maintain the integrity of the hole during the initial drilling phase of Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003. A 20-in. conductor pipe will be used for this purpose.

The selection criteria for the conductor pipe is based on the clearance required for the surface casing borehole. The conductor pipe will have an ID of 18.75 in. so that a 13-1/2 in. bit can be used to clean out the conductor pipe and drill the following section of each well to a depth of 3,250 ft for each injection well.

The engineering and design parameters for the selected conductor pipe are summarized in Table 4-9:

Table 4-9 – Parameters for the Selected Conductor Pipe – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Conductor Pipe								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(lbs)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
20 in., 129.33#, X-42, Welded	129.33	280	1,598,000	1,300	2,360	0.3415	18.75	NA
Using Mud Weight of 10 ppg – Design Criteria			36,212	146	146			
Safety Factor			44.13	8.93	16.21			

*ppf – pounds per foot
bbl/ft – barrels per foot
ppg – pounds per gallon

4.2.1.2 Surface Casing

The surface holes of the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 will be drilled to below the USDW at a depth of 3,250 ft for each well. The holes will be drilled and completed using a 13-1/2 in. bit and a 9-5/8 in. casing to allow sufficient annular space for consistent thickness of cement between the surface casing hole and the open hole. The casing will be set below the base of the USDW in a confining bed. To ensure cement is circulated to the surface and to promote an adequate cement bond, a series of centralizers will be installed on the surface casing strings and, if necessary, a top job performed, should the top-of-cement level fall after the cement is circulated. The cement will provide a barrier along the surface casing from shoe to surface to protect the USDW. Following cementing operations, a cement bond log will be run to evaluate and verify bonding throughout the surface holes.

The engineering and design parameters for the surface casing of the three proposed injectors are summarized in Tables 4-10 through 4-14:

Table 4-10 – Surface Casing Engineering Calculations – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Surface Casing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(lbs)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
9-5/8 in., 40.0#, J-55, LTC	40	3,250	520,000	2,570	3,950	0.0758	8.835	8.750
Using Mud Weight of 10 ppg – Design Criteria			130,000	1,690	1,690			
Safety Factor			4.00	1.52	2.34			

Table 4-11 – Surface Casing Annular Geometry – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Annular Geometry			
Section	**ID**	**MD**	**TVD**
	(in.)	**(ft)**	**(ft)**
Drive Pipe	18.75	280	280
Open Hole	13.5	3,250	3,250

Table 4-12 – Surface Casing Specifications – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Casing					
Section	**OD**	**ID**	**Weight**	**MD**	**TVD**
	(in.)	**(in.)**	**(lb/ft)**	**(ft)**	**(ft)**
Surface	9.625	8.835	40	3,250	3,250

Table 4-13 – Surface Casing Cement – Simoneaux CCS Injectors No. 001, No. 002, and No. 003

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Cement	0	3,250	3,333

*cf – cubic foot

Table 4-14 – Surface Casing Detail Cement – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead Cement	280	1.4122	0	395
Open Hole/Casing Annulus Cement	2,970	0.4887	100	2,903
Shoe Track	80	0.4257	0	34

*cf/ft – cubic feet per foot

To ensure cement is circulated to the surface, 100% excess relative to the gauge hole is used in the openhole cement-volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.3 Long String Casing

The long string casing is the final, cemented string installed in the well and includes the following:

- The use of 25CR SDSS material, or equivalent, across the UCZ
- The use of downhole tools, including centralizers, float equipment, and stage tool

A metallurgical analysis was performed, incorporating the composition of the CO_2 injectate at downhole conditions, and is included in *Appendix D*. Based on the results, 25CR material will be installed across the UCZ to prevent corrosion and downhole failures.

To prevent CO_2 migration above the injection zone, corrosion-resistant cement will be run from TD of the well to the top of the UCZ. By using corrosion-resistant material, the cement barrier is resistant to carbonic acid, thereby maintaining the integrity of the confinement zone throughout the life of the project. Figures 4-1 through 4-3 (*Section 4.2*) illustrate the long string casing design.

The completion strategy for Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 includes a series of plugging and perforating operations for each of the pre-defined Miocene completion stages. The CO_2 injectate will be injected for a predetermined amount of time or volume for each completion stage, as determined by the plume model. Each well will be completed in a series, with injection into each discrete sub-interval until the gross injection interval for each well is developed.

Once the limits for an injection interval have been reached, each well will be plugged back above the active completion stage with an expandable bridge plug and CO_2-resistant cement, and the next completion stage accessed by perforating the next stage. The monitoring equipment is designed to measure and record bottomhole pressure within the tubing and tubing-casing annulus (TCA), as discussed in *Section 5 – Testing and Monitoring Plan.*

The engineering and design parameters for the long string casing are summarized in Tables 4-15 through 4-29.

Table 4-15 – Long String Casing Engineering Calculations – Simoneaux CCS Injector Well No. 001

Long String Casing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(lbs)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
7 in., 26#, HCL-80, LTC	26	3,260	570,000	7,800	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			259,350	1,780	1,780			
Safety Factor			2.20	4.38	4.07			
7 in., 26#, 25CR-80, VAM-21	26	8,100	604,000	5,410	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			174,590	4,423	4,423			
Safety Factor			3.46	1.22	1.64			
7 in., 26#, HCL-80, LTC	26	9,975	570,000	7,800	7,24	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			48,750	5,446	5,446			
Safety Factor			11.69	1.43	1.33			

Table 4-16 – Long String Casing Engineering Calculations – Simoneaux CCS Injector Well No. 002

Long String Casing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(lbs)**	**(lbs)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
7 in., 26#, HCL-80, LTC	26	3,260	570,000	7,800	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			208,260	1,780	1,780			
Safety Factor			2.74	4.38	4.07			
7 in., 26#, 25CR-80, VAM-21	26	6,800	604,000	5,410	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			123,500	3,713	3,713			
Safety Factor			4.89	1.46	1.95			
7 in., 26#, HCL-80, LTC	26	8,010	570,000	7,800	7,24	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			31,460	4,373	4,373			
Safety Factor			18.12	1.78	1.66			

Table 4-17 – Long String Casing Engineering Calculations – Simoneaux CCS Injector Well No. 003

Long String Casing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(lbs)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
7 in., 26#, HCL-80, LTC	26	3,260	570,000	7,800	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			175,708	1,780	1,780			
Safety Factor			3.24	4.38	4.07			
7 in., 26#, 25CR-80, VAM-21	26	5,040	604,000	5,410	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			90,948	2,752	2,752			
Safety Factor			6.64	1.97	2.63			
7 in., 26#, HCL-80, LTC	26	6,758	570,000	7,800	7,240	0.0383	6.276	6.151
Using Mud Weight of 10.5 ppg – Design Criteria			44,668	3,690	3,690			
Safety Factor			12.76	2.11	1.96			

Table 4-18 – Long String Casing Annular Geometry – Simoneaux CCS Injector Well No. 001

Annular Geometry			
Section	**ID**	**MD**	**TVD**
	(in.)	**(ft)**	**(ft)**
Surface Casing	8.835	3,250	3,250
Open Hole	8.75	9,975	9,975

Table 4-19 – Long String Casing Annular Geometry – Simoneaux CCS Injector Well No. 002

Annular Geometry			
Section	**ID**	**MD**	**TVD**
	(in.)	**(ft)**	**(ft)**
Surface Casing	8.835	3,250	3,250
Open Hole	8.75	8,010	8,010

Table 4-20 – Long String Casing Annular Geometry – Simoneaux CCS Injector Well No. 003

Annular Geometry			
Section	ID (in.)	MD (ft)	TVD (ft)
Surface Casing	8.835	3,250	3,250
Open Hole	8.75	6,758	6,758

Table 4-21 – Long String Casing Specifications – Simoneaux CCS Injector Well No. 001

Casing					
Section	OD (in.)	ID (in.)	Weight (lb/ft)	MD (ft)	TVD (ft)
Long String	7	6.276	26	9,975	9,975

Table 4-22 – Long String Casing Specifications – Simoneaux CCS Injector Well No. 002

Casing					
Section	OD (in.)	ID (in.)	Weight (lb/ft)	MD (ft)	TVD (ft)
Long String	7	6.276	26	8,010	8,010

Table 4-23 – Long String Casing Specifications – Simoneaux CCS Injector No. 003

Casing					
Section	OD (in.)	ID (in.)	Weight (lb/ft)	MD (ft)	TVD (ft)
Long String	7	6.276	26	6,758	6,758

Table 4-24 – Long String Casing Cement – Simoneaux CCS Injector Well No. 001

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Stage 2 Lead	0	3,260	515
Stage 2 Tail	3,250	5,000	316
Stage 1	5,000	9,975	915

Table 4-25 – Long String Casing Cement – Simoneaux CCS Injector Well No. 002

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Stage 2 Lead	0	3,250	515
Stage 2 Tail	3,250	5,000	316
Stage 1	5,000	8,010	560

Table 4-26 – Long String Casing Cement – Simoneaux CCS Injector Well No. 003

Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(cf)
Stage 2 Lead	0	3,250	515
Stage 2 Tail	3,250	4,000	135
Stage 1	4,000	6,758	515

Table 4-27 – Long String Casing Detail Cement – Simoneaux CCS Injector Well No. 001

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Long String Casing / Surface Casing Annulus – Stage 2 Lead	3,250	0.1585	0	515
Long String Casing / 8-3/4 in. Open Hole – Stage 2 Tail	1,750	0.1503	20	316
Long String Casing / 8-3/4 in. Open Hole – Stage 1	4,975	0.1503	20	897
Shoe Track	80	0.2148	0	17

Table 4-28 – Long String Casing Detail Cement – Simoneaux CCS Injector Well No. 002

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Long String Casing / Surface Casing Annulus – Stage 2 Lead	3,250	0.1585	0	515
Long String Casing / 8-3/4 in. Open Hole – Stage 2 Tail	1,750	0.1503	20	316
Long String Casing / 8-3/4 in. Open Hole – Stage 1	3,010	0.1503	20	543
Shoe Track	80	0.2148	0	17

Table 4-29 – Long String Casing Detail Cement – Simoneaux CCS Injector Well No. 003

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Long String Casing / Surface Casing Annulus – Stage 2 Lead	3,250	0.1585	0	515
Long String Casing / 8-3/4 in. Open Hole – Stage 2 Tail	750	0.1503	20	135
Long String Casing / 8-3/4 in. Open Hole – Stage 1	2,758	0.1503	20	498
Shoe Track	80	0.2148	0	17

To ensure cement is circulated to the surface, 20% excess relative to the gauge hole is used in the openhole cement-volume calculations. Excess cement volumes may be adjusted based on the openhole caliper log.

4.2.1.4 Centralizers

The selection and installation of centralizers for the proposed Libra Project injection wells will provide centralization of the casing in the borehole. The use of bow-spring centralizers in the design for the 9-5/8 in. surface casing will ensure that a continuous, uniform cement column is placed throughout the 13-1/2 in. x 9-5/8 in. annulus. The recommended centralizer placement is as follows:

(1) – Every third joint (120 ft) to surface
Total centralizers – 28 for each of the injectors

The use of bow-spring centralizers in the design for the 7-in. long string casing will ensure that a continuous, uniform cement column is placed throughout the 8-3/4 in. x 7 in. annulus. The recommended centralizer placement is as follows:

(1) – Above shoe joint
(2) – Every third joint (120 ft) to surface
Total centralizers – 84, 67, and 57 for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively

4.2.1.5 Injection Tubing

The injection tubing design for the injection wells incorporates 4-1/2 in. tubing and is based on the injection volume, injection rate, and injectate composition. The casing selection considers the conditions that result from the combination of the injectate and formation fluids. An L-80 grade tubing string was selected, and the tubing casing annulus will be continuously monitored during the operation. Additionally, 20 ft of 25CR SDSS-80 ksi will be installed at the bottom of the tubing string to facilitate installation of the pressure gauge mandrel and safety injection valve.

Tables 4-30 through 4-32 provide the tubing design and calculations for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.

Table 4-30 – Tubing Engineering Design Calculations – Simoneaux CCS Injector Well No. 001

Tubing								
Description	**Casing Wt.**	**Depth**	**Tensile**	**Collapse**	**Burst**	**Capacity**	**ID**	**Drift ID**
	(ppf)	**(ft)**	**(psi)**	**(psi)**	**(psi)**	**(bbl/ft)**	**(in.)**	**(in.)**
4-1/2 in., 11.6#, L-80, LTC	11.6	7,970	212,000	6,350	7,780	0.0155	4.000	3.875
			92,452	5,551	6,902			
Safety Factor			2.29	1.14	1.13			
4-1/2 in., 11.6#, 25CR-80 ksi, VAM-21	11.6	7,990	267,000	6,360	7,780	0.0155	4.000	3.875
			232	5,558	6,913			
Safety Factor			1,150.86	1.14	1.13			
		Evacuated tubing, 7.0 ppg brine on backside with 2,650 psi applied						
		Evacuated annulus, full column of 10.5 ppg mud with 2,550 psi applied						

Table 4-31 – Tubing Engineering Design Calculations – Simoneaux CCS Injector Well No. 002

Tubing								
Description	Casing Wt. (ppf)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
4-1/2 in., 11.6#, L-80, LTC	11.6	6,630	212,000	6,350	7,780	0.0155	4.000	3.875
			77,140	4,813	5,920			
Safety Factor			2.75	1.32	1.31			
4-1/2 in., 11.6#, 25CR-80 ksi, VAM-21	11.6	6,650	267,000	6,360	7,780	0.0155	4.000	3.875
			232	4,821	5,931			
Safety Factor			1,150.86	1.32	1.32			
		Evacuated tubing, 7.0 ppg brine on backside with 2,400 psi applied						
		Evacuated annulus, full column of 10.5 ppg mud with 2,300 psi applied						

Table 4-32 – Tubing Engineering Design Calculations – Simoneaux CCS Injector Well No. 003

Tubing								
Description	Casing Wt. (ppf)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
4-1/2 in., 11.6#, L-80, LTC	11.6	4,910	212,000	6,350	7,780	0.0155	4.000	3.875
			57,188	3,287	4,081			
Safety Factor			3.71	1.93	1.91			
4-1/2 in., 11.6#, 25CR-80 ksi, VAM-21	11.6	4,930	267,000	6,360	7,780	0.0155	4.000	3.875
			232	3,295	4,092			
Safety Factor			1,150.86	1.93	1.90			
		Evacuated tubing, 7.0 ppg brine on backside with 1,500 psi applied						
		Evacuated annulus, full column of 10.5 ppg mud with 1,400 psi applied						

4.2.1.6 Packer Assembly

The injection packer for the proposed injection wells will include a 7 in. x 4-1/2 in. CRA packer installed in the 7-in. casing. The flow-wetted components were selected based on the results of the metallurgical analysis and include corrosion-resistant components, 25CR SDSS or equivalent, to ensure compatibility with the expected downhole conditions. Prior to engaging the packer seal assembly, the TCA will be circulated and filled with noncorrosive fluid.

4.2.1.7 Tubing Encapsulated Conductor and Pressure Gauge Assembly

Tubing Encapsulated Conductor and Pressure Gauge Array

A TEC will be installed on the backside of the injection tubing and connected to gauges installed in the tubing string, immediately above the packer. The pressure gauges will monitor the bottomhole pressure and temperature of the active completion stage and TCA. The downhole data will be transmitted to the surface through the TEC line, providing real-time data for reservoir monitoring.

4.2.1.8 Safety Injection Valve

Safety Injection Valve

A downhole safety injection valve will be installed in a profile nipple, immediately above the gauges. The flow-wetted components were selected based on results of the metallurgical analysis and include corrosion-resistant components, 25CR SDSS or equivalent, to ensure compatibility with the expected downhole conditions. The valve will be set and retrieved with wireline operations.

Figures 4-7 through 4-9 provide a schematic of the general completion assembly for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.

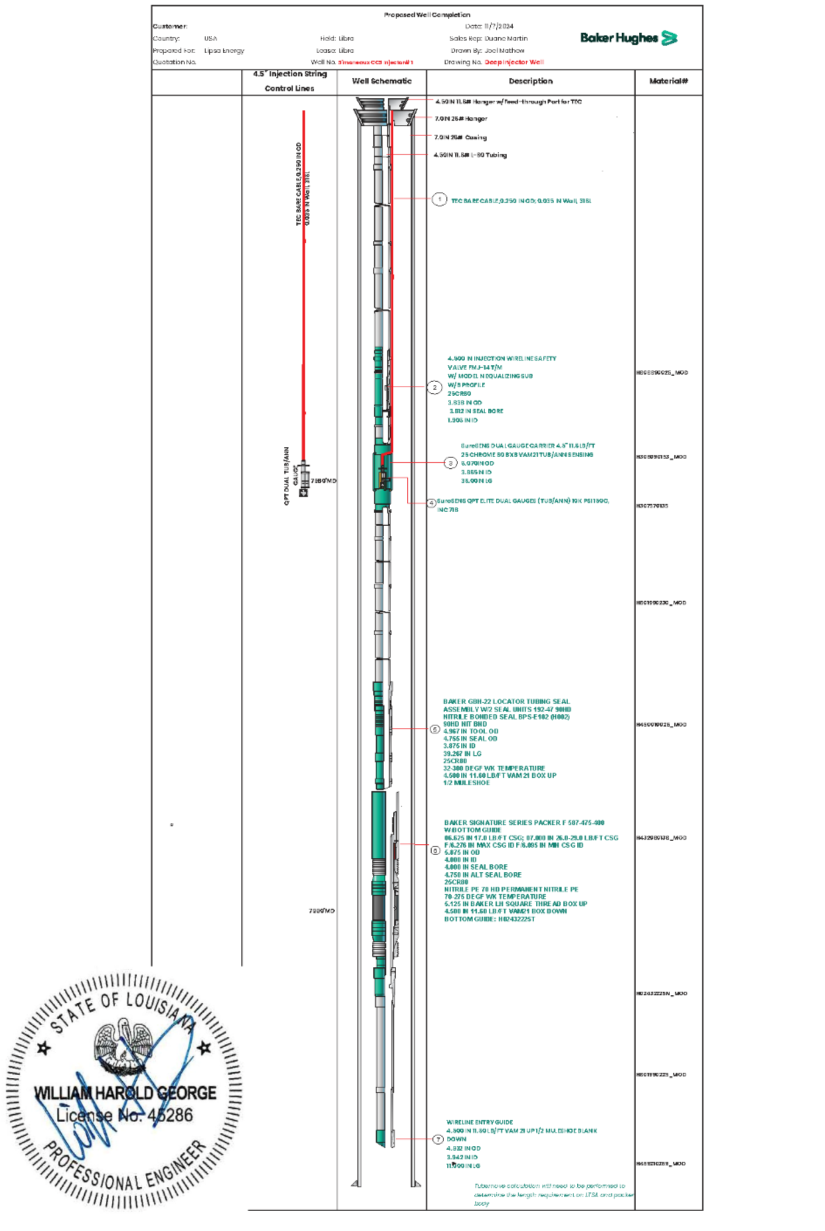


Figure 4-7 – Simoneaux CCS Injector Well No. 001 Completion Assembly Schematic

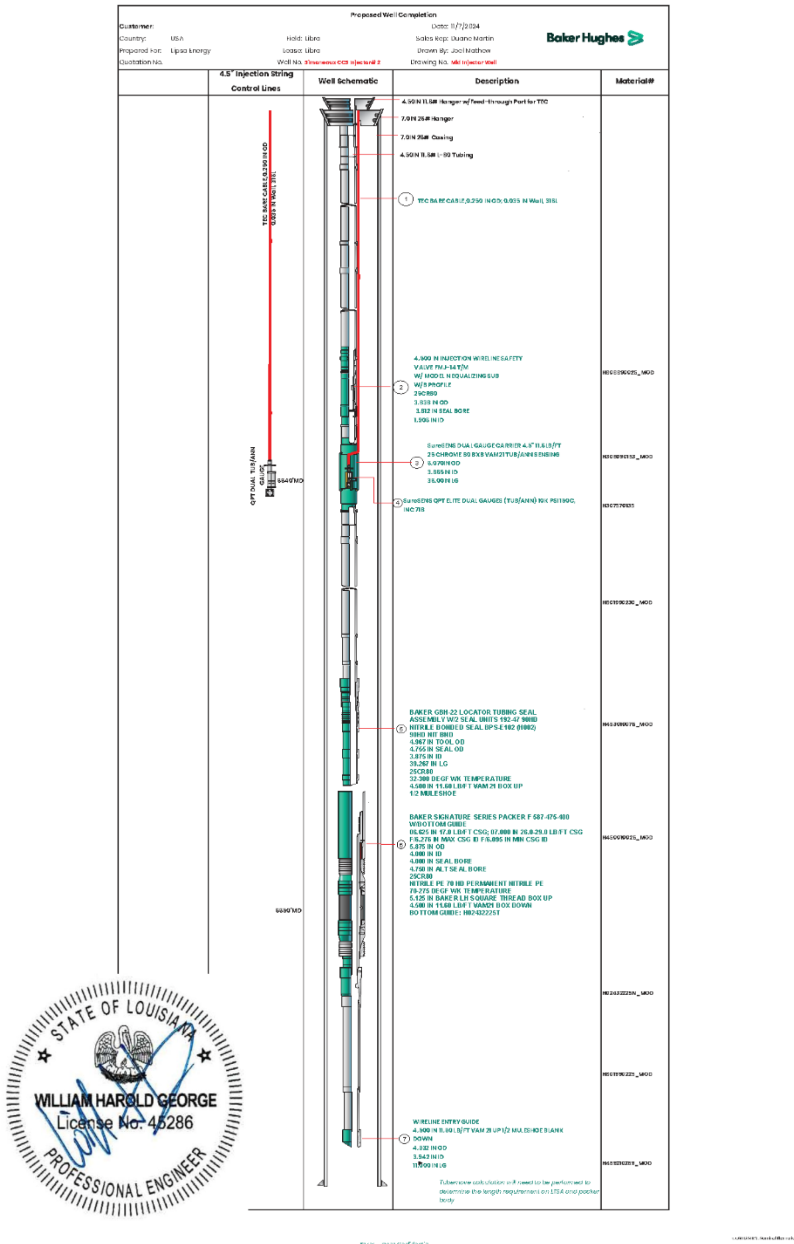


Figure 4-8 – Simoneaux CCS Injector Well No. 002 Completion Assembly Schematic

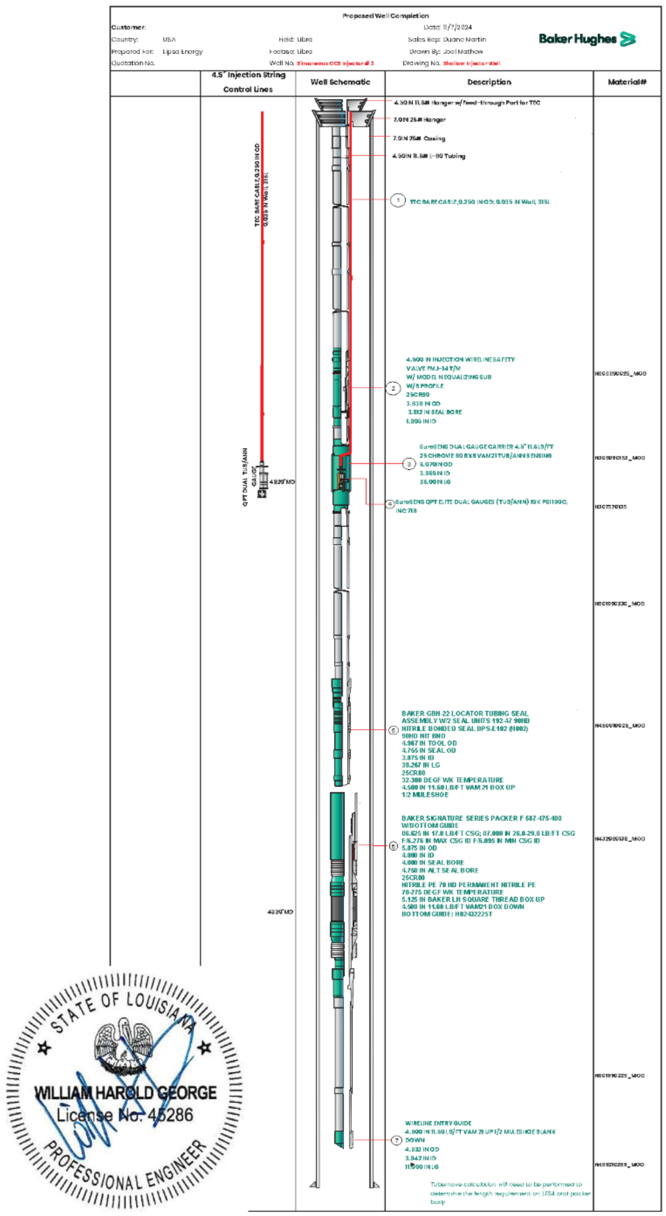


Figure 4-9 – Simoneaux CCS Injector Well No. 003 Completion Assembly Schematic

4.2.1.9 Wellhead Schematic

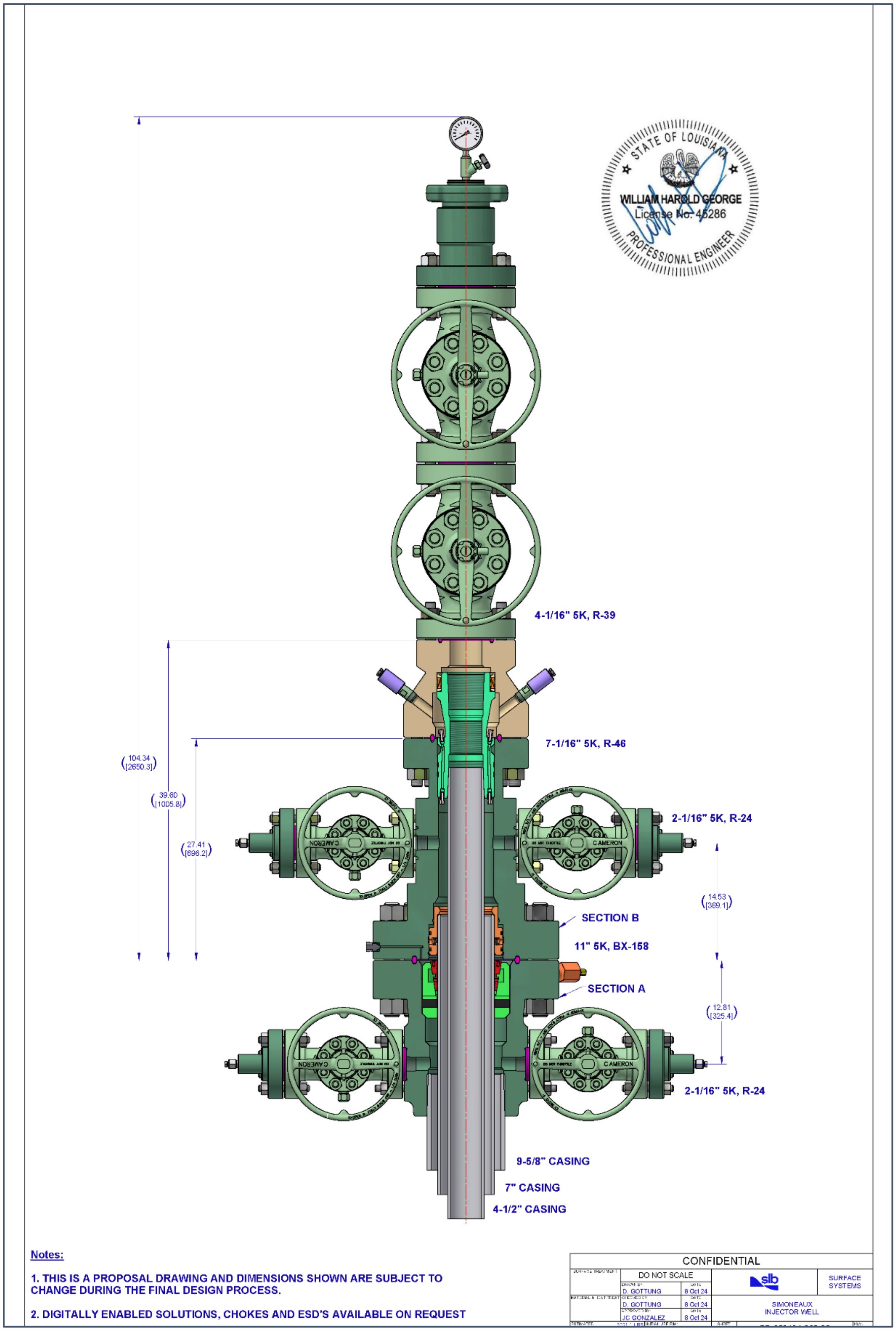


Figure 4-10 – Preliminary Wellhead Design: Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

4.3 Testing and Logging During Drilling and Completion Operations

Lapis will notify the Office of Conservation at least 72 hours before conducting any wireline logs, well tests, or reservoir tests

4.3.1 Coring Plan

Lapis plans to collect whole core of the UCZ, injection zone, and lower confining zone (LCZ) during the drilling process of the stratigraphic test well. Supplementary sidewall cores of the injection and confining zones may be collected from the proposed injection wells, if necessary.

4.3.2 Logging Plan

The Libra Project logging plan involves an extensive suite of electric logs for both the openhole and cased-hole sections. A detailed list of the openhole and cased hole logging plan is included in Table 4-33 for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.

Table 4-33 – Openhole and Cased-Hole Logging Plan – Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003

		Simoneaux Strat Well No. 001		Simoneaux CCS Injector Well No. 001		Simoneaux CCS Injector Well No. 002		Simoneaux CCS Injector Well No. 003	
		Surface Run	TD Run	Surface Run	TD Run	Surface Run	TD Run	Surface Run	TD Run
	Data	0–3,100	3,100–10,070	0–3,300	3,300–9,975	0–3,300	3,300–8,010	0–3,300	3,300–6,295
Open Hole	**Spontaneous Potential**	x	x	x	x	x	x	x	x
	Gamma Ray	x	x	x	x	x	x	x	x
	Density	x	x	x	x	x	x	x	x
	Neutron	x	x	x	x	x	x	x	x
	Resistivity	x	x	x	x	x	x	x	x
	Dipole Acoustic		x		x				
	NMR		x		x				
	Image log		x		x				
	Spectral Gamma		x		x				
	Pore Pressure	x	x		x				
	Fluid Sample	x	x		x				
	Stress Test		x		x				
	Sidewall Core		x		x				
	Zero Offset VSP		x		x				
Cased Hole	**Cement Bond**	x	x	x	x	x	x	x	x
	Temperature		x		x		x		x
	Pulse Neutron		x		x		x		x
	Casing Inspection		x		x		x		x

* NMR – nuclear magnetic resonance | VSP – vertical seismic profile

4.3.3 Formation Fluid Testing

Prior to setting the long string casing, formation fluid samples will be collected. The fluid will be obtained through an openhole fluid recovery tool, and the sample intervals will be determined based on the openhole log evaluation.

4.3.4 Step-Rate Injection and Falloff Test

A step-rate injection test and pressure falloff test will be conducted on each of the proposed injection wells prior to injection. The step-rate and falloff tests will be performed on the first injection stage of each well, and—prior to performing the tests—the details and procedures of the tests will be submitted to and approved by the LDENR.

4.4 Injection Well Operating Strategy

The Libra Project is designed to inject a total of 4 MMT/yr of CO_2 in the proposed Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003. The CO_2 injectate will remain in the supercritical state during the injection process. The Miocene sand intervals that will be completed within the gross injection interval are characteristic of high porosity and permeability, which will allow the pressure inducted by injection to be absorbed and dissipated within the reservoir. The surface and bottomhole injection pressures are provided in Table 4-34.

Table 4-3434 – Injection Parameters for the Proposed Injection Wells

Parameter	Injector No. 001	Injector No. 002	Injector No. 003
Gross Injection Zone	8,168 ft to 9,824 ft	6,838 ft to 7,860 ft	5,129 ft to 6,608 ft
Maximum Injection Volume	1.5 MMT/yr	1.5 MMT/yr	1.0 MMT/yr
Average Injection Volume	1.5 MMT/yr	1.5 MMT/yr	1.0 MMT/yr
Maximum Increase in BHP	657 psi	640 psi	267 psi
Maximum Allowed BHP (90% of Estimated Fracture Gradient)	7,233 psi	5,306 psi	4,068 psi
Modeled Maximum Surface Pressure Injection	2,532 psi	2,288 psi	1,374 psi
Maximum Annular Pressure	>100 psi over injection pressure	>100 psi over injection pressure	>100 psi over injection pressure

The surface injection pressures will be limited by the BHP, so that it does not exceed 90% of the fracture pressure at the injection zone. The surface and bottomhole injection pressures were modeled for each stage, along with the maximum allowed BHP, shown in Tables 4-35 through 4-37 for the three injectors, respectively.

Table 4-3535 – Injection Pressures and Volumes by Stage – Simoneaux CCS Injector Well No. 001

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowed BHP (psi)	Maximum Modeled BHP (psi)	Maximum Modeled WHP (psi)
1	1/1/2027	9,187	8,036	7,233	4,818	2,520
2	1/1/2037	8,168	6,845	6,161	4,470	2,532

Table 4-3636 – Injection Pressures and Volumes by Stage – Simoneaux CCS Injector Well No. 002

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowed BHP (psi)	Maximum Modeled BHP (psi)	Maximum Modeled WHP (psi)
1	1/1/2028	7,306	5,896	5,306	3,901	2,213
2	1/1/2038	6,838	5,403	4,863	3,834	2,288

Table 4-3737 – Injection Pressures and Volumes by Stage – Simoneaux CCS Injector Well No. 003

Completion Stage	Completion Date	Top Depth (ft)	Fracture Pressure (psi)	Maximum Allowed BHP (psi)	Maximum Modeled BHP (psi)	Maximum Modeled WHP (psi)
1	1/1/2029	5,959	4,520	4,068	3,046	1,374
2	1/1/2039	5,129	3,737	3,363	2,666	1,292

The wells will be completed in multiple completion stages to occupy the available pore space most effectively. The predefined completion stages were selected to maximize storage capacity and the use of the acreage position for the project. A summary table of the planned injection strategy for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 is displayed in Tables 4-38 through 4-40, respectively.

Table 4-3838 – Completion Stages – Simoneaux CCS Injector Well No. 001

Completion Stage	Completion Date	Injection Duration (months)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
1	1/1/2027	120	9,187	9,824	390

2	1/1/2037	120	8,168	8,990	448

Table 4-3939 – Completion Stages – Simoneaux CCS Injector Well No. 002

Completion Stage	Completion Date	Injection Duration (months)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
1	1/1/2028	120	7,306	7,860	283
2	1/1/2038	108	6,838	7,245	153

Table 4-4040 – Completion Stages – Simoneaux CCS Injector Well No. 003

Completion Stage	Completion Date	Injection Duration (months)	Top Depth (ft)	Bottom Depth (ft)	Net Pay (ft)
1	1/1/2029	120	5,959	6,608	230
2	1/1/2039	96	5,129	5,817	257

4.5 Injection Well Zonal Isolation

The injection wells will be completed in a series of completion stages. The injection well completion strategy will involve completing the deepest injection interval, plugging the interval once injection is complete, and recompleting into the final shallower interval until injection for the final completion stage is complete. The CO_2 will be injected into each completion stage for a discrete period, which will be determined by the plume modeling and the plume boundary extent in relation to the pore space ownership.

The following details outline the plug-back procedures for the proposed injection and monitoring wells. For the Libra Project, the types of plugs utilized in the plug-back that will be used include the following:

- Expandable bridge plugs will isolate each completion stage in the injection well.
- Corrosion-resistant cement will be set on top of the expandable plug.

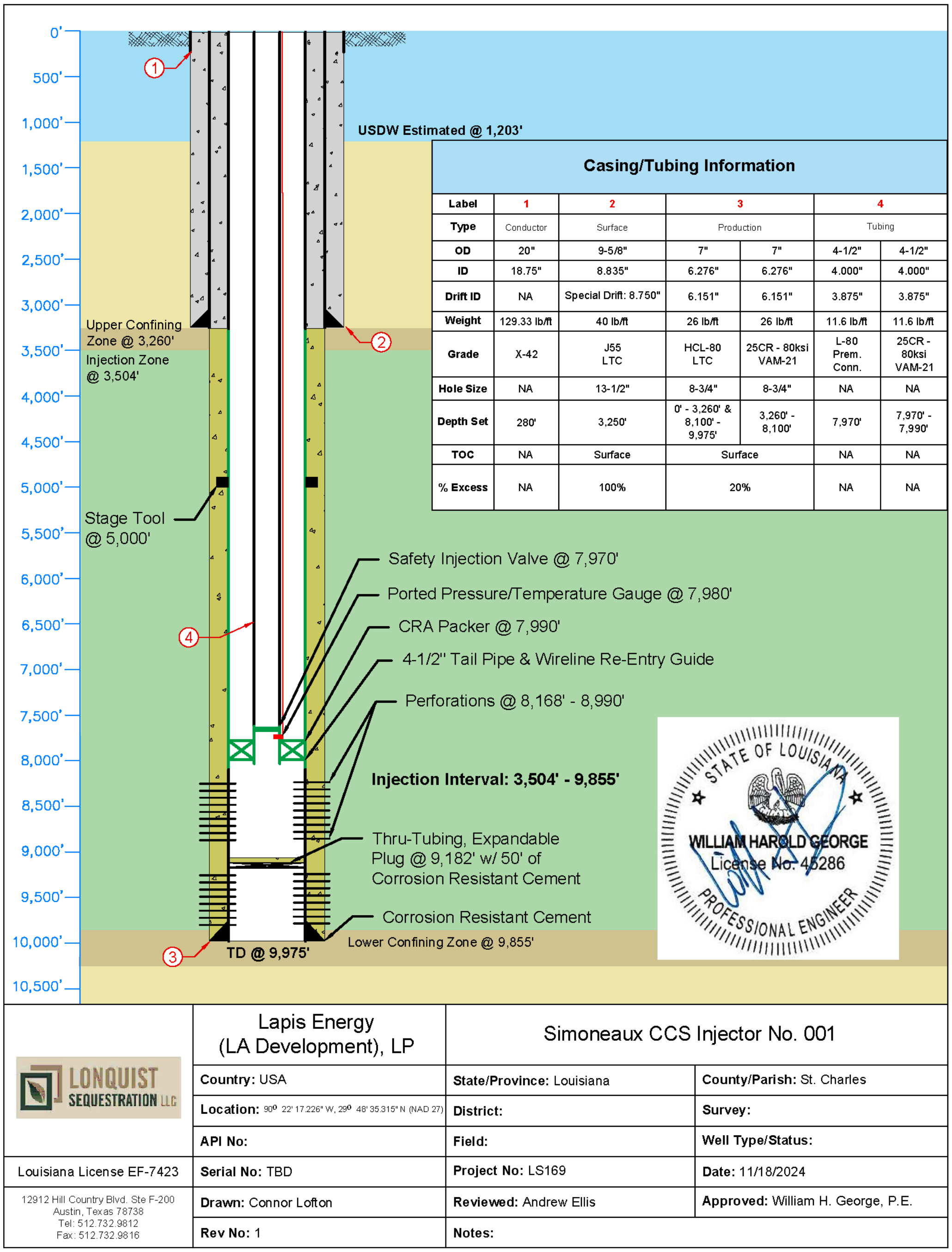
4.5.1.1 Pre-zonal Isolation Activities

Lapis will comply with all reporting and notification provisions, as follows:

- Notice of Intent to Plug will be communicated to the LDENR by submitting Form UIC-17 with detailed plans. (SWO 29-N-6 **§3631.A.4**)
- No actual well-plugging operations will commence until written approval from the Commissioner of Conservation (Commissioner) is received.
- The bottomhole pressure will be measured with the TEC, which is installed on the exterior of the injection tubing and connects to the ported pressure gauge mandrel set above the packer, as discussed in *Section 5 – Testing and Monitoring Plan*. (SWO 29-N-6 **§3631.A.2** [40 CFR ***§*146.92(a)**])

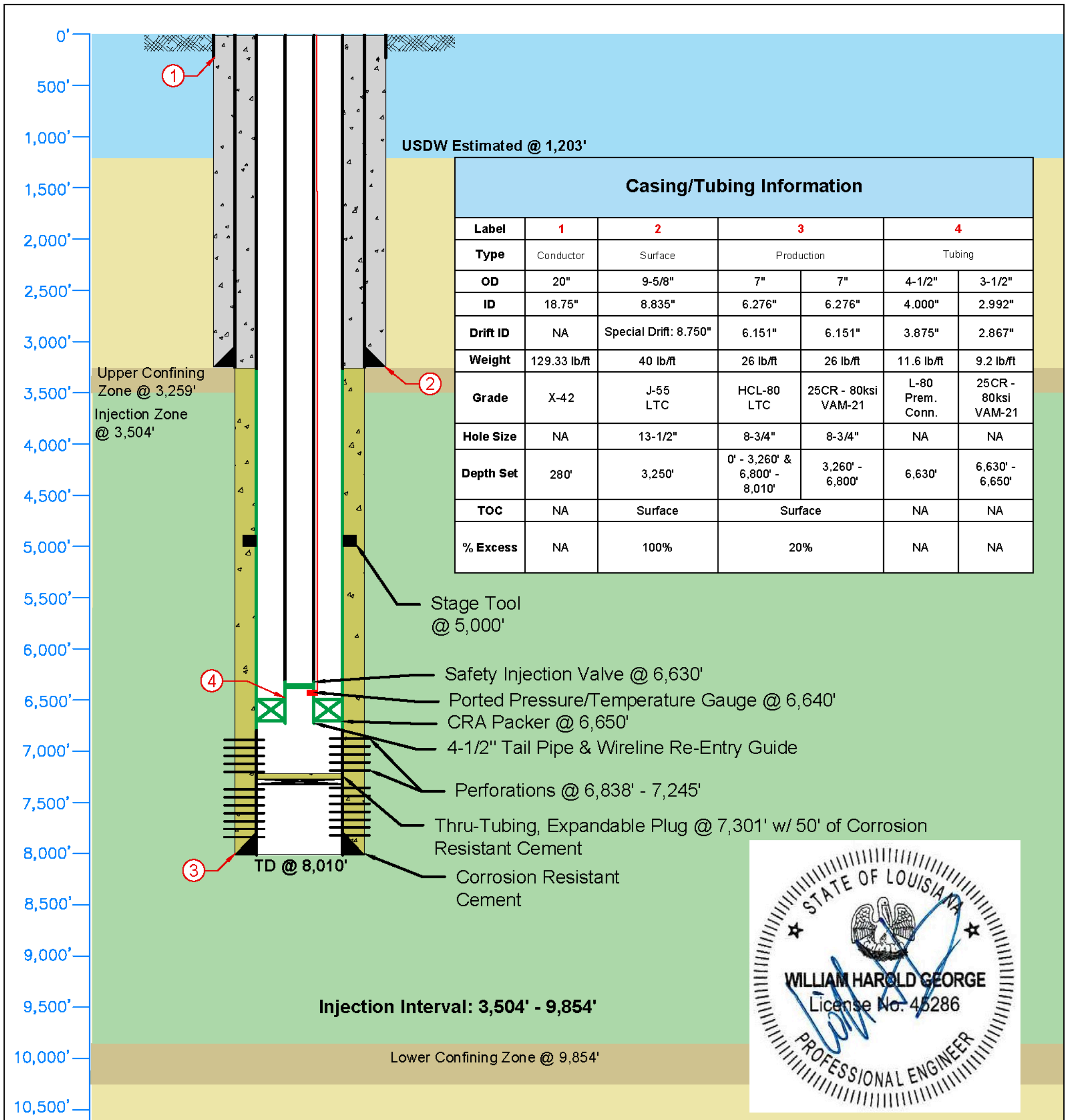
- External mechanical integrity will be demonstrated through the approved monitoring methods described in *Section 5*. (SWO 29-N-6 **§3631.A.2** [40 CFR **§146.92(a)**])

Figures 4-11 through 4-13 show the zonal isolation of the first completion stage in the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.



Label	1	2	3	3	4	4
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'	7,970'	7,970' - 7,990'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

Figure 4-11 – Zonal Isolation Schematic for Simoneaux CCS Injector Well No. 001

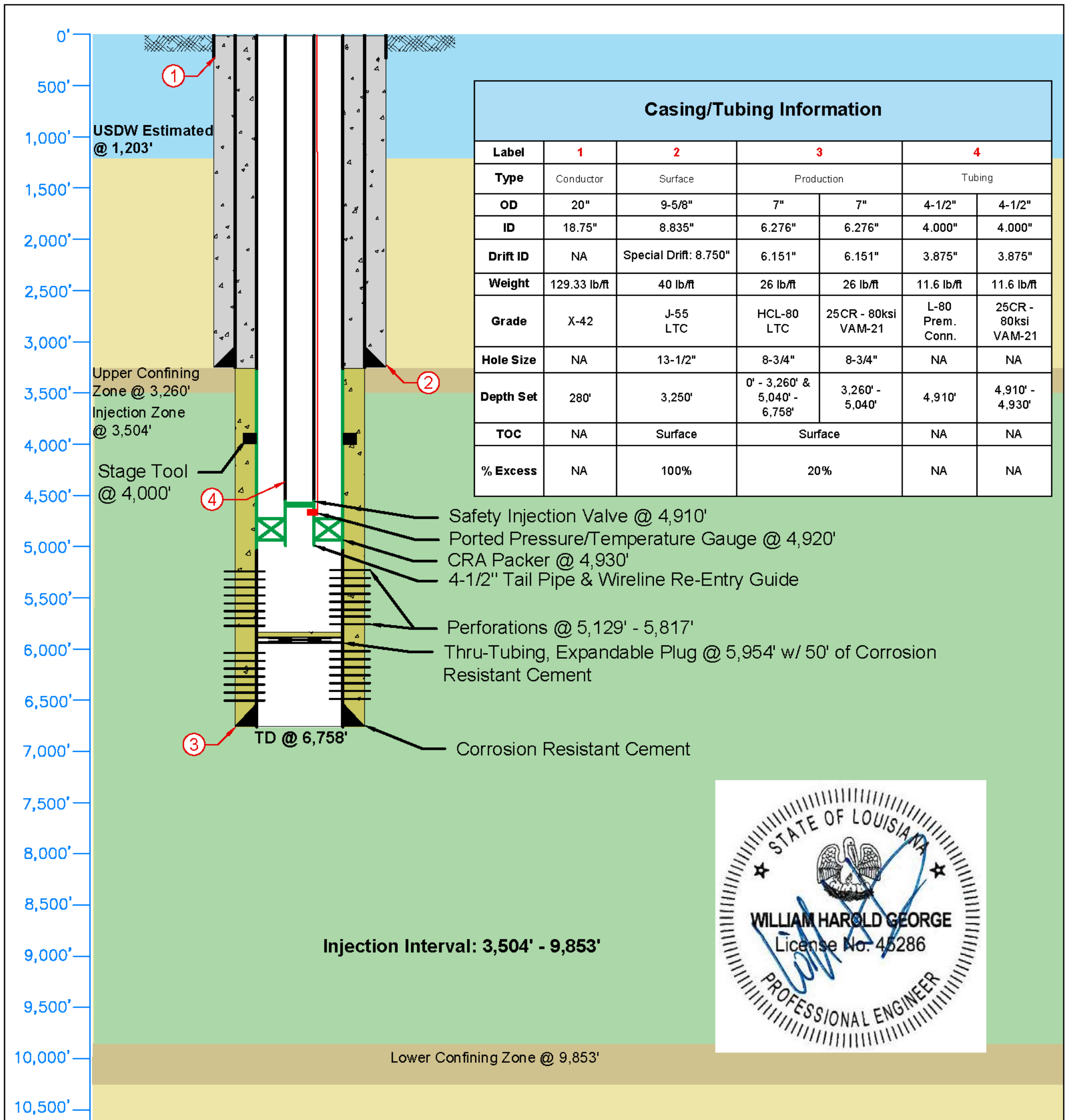


Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	3-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	2.992"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	2.867"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	9.2 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'	6,630'	6,630' - 6,650'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.510" W, 29º 48' 35.317" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 4-12 – Zonal Isolation Schematic for Simoneaux CCS Injector Well No. 002



Casing/Tubing Information

Label	1	2	3		4	
Type	Conductor	Surface	Production		Tubing	
OD	20"	9-5/8"	7"	7"	4-1/2"	4-1/2"
ID	18.75"	8.835"	6.276"	6.276"	4.000"	4.000"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"	3.875"	3.875"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft	11.6 lb/ft	11.6 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21	L-80 Prem. Conn.	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"	NA	NA
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'	4,910'	4,910' - 4,930'
TOC	NA	Surface	Surface		NA	NA
% Excess	NA	100%	20%		NA	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.793 W, 29° 48' 35.319" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 4-13 – Zonal Isolation Schematic for Simoneaux CCS Injector Well No. 003

4.5.1.2 Zonal Isolation Activities

1. An expandable bridge plug and CO_2-resistant cement will be placed above the active completion stage.
2. A pressure test will be conducted to confirm that the plug is properly set.

The proposed injection well designs allow for zonal isolation to be achieved by isolating the existing perforations and perforating the next completion stage.

Typical densities for the injectate range from 40.9 pounds per cubic foot (lb/ft^3) in the shallowest completion stage to 44.4 lb/ft^3 in the deepest completion stage. This is compared to approximately 66.6 lb/ft^3 for the connate brine in the same formations. This density difference and the high vertical permeability in the Miocene sands allow the CO_2 to migrate vertically to the top of each discrete completion stage—and laterally under the confining layer of that completion stage.

In a simplified homogeneous model, this results in a significant "mushroom cap" effect, with the top of the mushroom expanding outwardly from the injection well. This effect is generally depicted in Figure 4-12. Site-specific data will be collected from a stratigraphic test well that will provide greater insight into the heterogeneity of the rock and vertical migration of the CO_2.

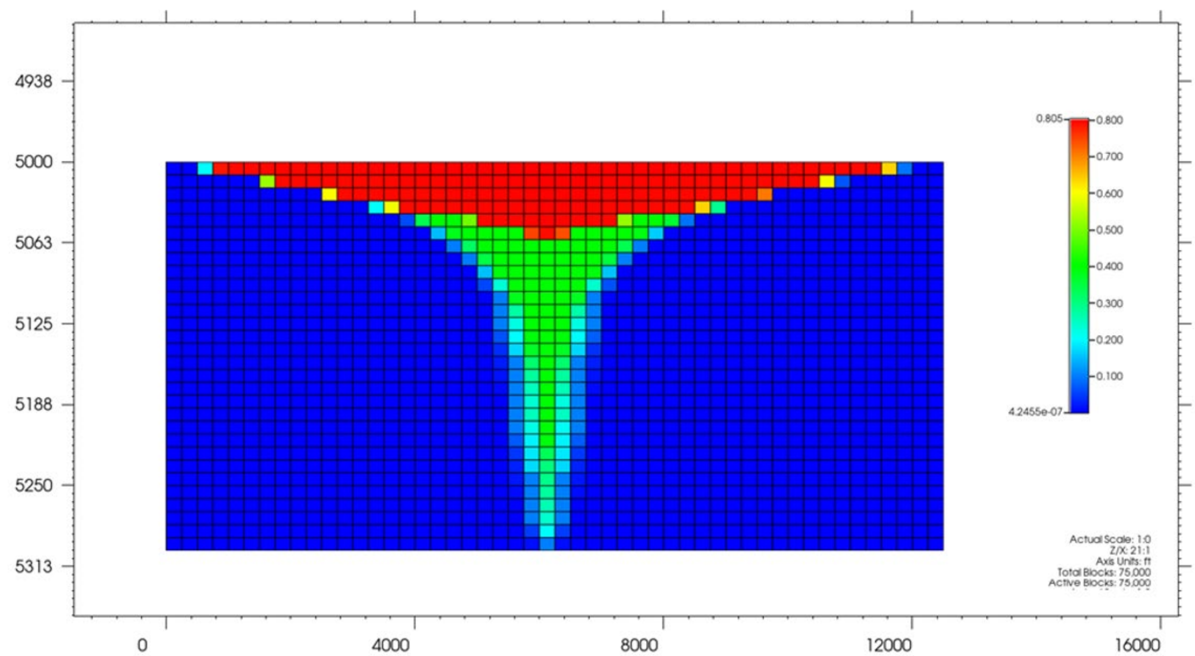


Figure 4-14 – Typical Plume Profile in High Permeability Formations

To maximize the utilization of pore space, discrete completion stages must be identified. Through modeling of injection in the reservoir, a CO_2 plume model was built based on the well-specific completion strategy. From that strategy, a plume map and pressure front map were generated and used to determine the lateral extent of the plume, which were then used to confirm the ownership of the pore space that will be impacted by the CO_2 plume.

Reservoir management is important for sequestration wells in thick, high-permeability, unconsolidated sand formations. At the end of each completion stage, wireline operations will be executed to recomplete into a new stage. A plug will be set to isolate the previous stage, and the 7-in. long string casing will be perforated to access the next stage for injection.

4.6 Injection Well Construction and Operation Summary

The proposed Libra Project injection wells were engineered and designed to meet or exceed the Underground Injection Control (UIC) standards, mitigate risks associated with Class VI injection wells, and protect the USDW. The well construction materials, completion, procedure, and set points meet the requirements for this classification of injection well and optimize pore space and time associated with operating the wells.

The available reservoir storage, proximity to CO_2 emitters, and plume orientation relative to the acreage boundary make the Lapis project suitable for carbon sequestration purposes. Combining an extensive monitoring system, best engineering practices, and reservoir management strategy, these wells will safely serve the state of Louisiana for years to come.

The following are included in *Appendix D – Well Construction Schematics and Procedures*:

- Appendix D-1 Drilling and Completion Prognosis – Simoneaux CCS Injector Well No. 001
- Appendix D-2 Drilling and Completion Prognosis – Simoneaux CCS Injector Well No. 002
- Appendix D-3 Drilling and Completion Prognosis – Simoneaux CCS Injector Well No. 003
- Appendix D-4 Drilling and Completion Wellbore Schematic – Simoneaux CCS Injector Well No. 001
- Appendix D-5 Drilling and Completion Wellbore Schematic – Simoneaux CCS Injector Well No. 002
- Appendix D-6 Drilling and Completion Wellbore Schematic – Simoneaux CCS Injector Well No. 003
- Appendix D-7 Recompletion Wellbore Schematic – Simoneaux CCS Injector Well No. 001
- Appendix D-8 Recompletion Wellbore Schematic – Simoneaux CCS Injector Well No. 002
- Appendix D-9 Recompletion Wellbore Schematic – Simoneaux CCS Injector Well No. 003
- Appendix D-10 Mud Program – Simoneaux CCS Injector Wells No. 001, No. 002, No. 003
- Appendix D-11 Cement Program – Simoneaux CCS Injector Well No. 001
- Appendix D-12 Cement Program – Simoneaux CCS Injector Well No. 002
- Appendix D-13 Cement Program – Simoneaux CCS Injector Well No. 003
- Appendix D-14 Completion Assembly Schematic – Simoneaux CCS Injector Well No. 001
- Appendix D-15 Completion Assembly Schematic – Simoneaux CCS Injector Well No. 002

- Appendix D-16   Completion Assembly Schematic – Simoneaux CCS Injector Well No. 003
- Appendix D-17   Flow Assurance Study Steady-State Results Summary
- Appendix D-18   Wellhead Schematic – Simoneaux CCS Injector Wells No. 001, No. 002, No. 003
- Appendix E-1   Metallurgy Report

SECTION 5 – TESTING AND MONITORING PLAN

TABLE OF CONTENTS

Figures

Tables

5.1 Introduction

This section includes the proposed Testing and Monitoring Plan for the Lapis Energy (LA Development), LP (Lapis) Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, for Libra CO_2 Storage Solutions (Libra). The plan includes robust testing and monitoring programs that satisfy the requirements of Statewide Order (SWO) 29-N-6 **§3625.A** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. This plan will start before the injection of CO_2 commences. Monitoring strategies are designed to ensure and verify protection of Underground Sources of Drinking Water (USDW). These strategies consider, but are not limited to, the injection-stream composition, wellhead conditions, bottomhole operating parameters, seismic imaging for plume evolution, well integrity, and above-zone confinement conditions. Lapis will maintain mechanical integrity of the injection well at all times, except when doing well workovers, well maintenance, or well remedial work. The location and information for all new monitoring wells are included, as are the parameters to be measured at each location.

An in-depth summary of plume-growth monitoring, using time-lapse seismic imaging technology, is presented. The monitoring activities described in this plan will be carried out during the entirety of the life of the injection wells, including the post-injection site care (PISC) phase. These activities will follow a predetermined timeline tailored towards verifying that the observed plume development is according to modeling expectations, as well as demonstrating that the injected CO_2 is not endangering the USDW.

5.2 Reporting Requirements

Lapis will provide routine reports to the Commissioner of Conservation (Commissioner). The report contents and submittal frequencies are described as follows:

- Any noncompliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs
    - Verbal Notification – Reported within 24 hours of event
- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
    - Verbal Notification – Reported within 24 hours of event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of event
- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
    - Written Notification – Reported within 72 hours of composition change
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event
- Description of any event that triggers a shutoff device and the response taken
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event

Reports will include all contents and situations listed above, in addition to the following:

Semiannual Reports

- Monthly average, maximum, and minimum values of injection pressure, flow rate and volume, and annular pressure
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period, and the volume injected cumulatively over the life of the project
- Monthly annulus fluid volume added
- Raw operating data from the continuous recording devices, submitted in digital format
- Results of any monitoring as described here

Reports to be submitted within 30 days after the following events:

- Any well workover
- Any periodic tests of mechanical integrity
- Any test of the injection well conducted, if required by the Commissioner

Notification to the Commissioner, in writing, 30 days in advance of the following events:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of an injection well

Lapis will submit all reports, submittals, and notifications to the Louisiana Department of Energy and Natural Resources (LDENR) and ensure that all records are retained throughout the life of the project. Records for injected-fluid data, including nature and composition, will be retained for the 10-year period following site closure. Monitoring data will be retained for at least 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be kept for 10 years after site closure. All calibration and maintenance records will be maintained for a period of 3 years form the date of the test.

5.3 Testing Plan Review and Updates

The Testing and Monitoring Plan will be reviewed and revised as necessary, at a minimum of every 5 years, to incorporate collected monitoring data, operational data, and the most recent area of review (AOR) reevaluation. Plan amendments will also be submitted within 1 year of an AOR reevaluation. Amendments to the Testing and Monitoring Plan will further be submitted following any significant facility changes, such as the development of offset monitoring wells or newly permitted injection wells within the AOR, on a schedule determined by the Commissioner. Finally, plan amendments will be submitted as otherwise required by the Commissioner.

5.4 <u>Testing Strategies</u>

Multiple tests will be conducted to evaluate the integrity of the well and the reservoir behavior. These tests will take place before injection commences, and most will be repeated on a regular basis during injection to ensure safe injection operations.

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, Lapis will conduct a step-rate injectivity test to verify the fracture pressure estimated during the formation evaluation process. This test will be performed on the first individual set of perforations within Simoneaux CCS Injector Well No.001. The results of this step-rate test will be used along with detailed logging data to validate the fracture pressure of the remaining zones in each well. The details of the step-rate test are provided in *Section 4.3.4*.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

Lapis will ensure the mechanical integrity of the injection wells by performing an annulus pressure test after each well has been completed, prior to injection, annually, and after each recompletion into a new zone. An annulus pressure test will also be conducted after performing any well remedial work that involves unseating the tubing or packer. At no point will there be a period of more than 12 months between annulus pressure tests. This pressure test specifically verifies the integrity of the annulus between the casing and tubing above the packer. During well construction and prior to completion, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure, to verify its integrity. An agent of the Louisiana Office of Conservation must witness the annulus pressure tests.

The annulus pressure tests are designed to demonstrate the mechanical integrity of the casing, tubing, and packer. These tests are conducted by pressuring the annulus to a minimum of 500 pounds per square inch gauge (psig) surface pressure. A block valve is then used to isolate the test-pressure source from the test-pressure gauge upon test initiation, with all ports into the casing annulus closed except the one monitored by the test-pressure gauge. The test pressure will be monitored and recorded for a minimum of 30 minutes, using a pressure gauge with sensitivities that can indicate a loss of 5%. A lack of mechanical integrity is indicated by any loss of test pressure exceeding 5% during the minimum 30-minute duration.

All annulus pressure test results will be submitted to the LDENR Injection and Mining Division (IMD) within 30 days of completion.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. More details regarding continuous monitoring are described in *Sections 5.5.1* and *5.5.2.*

5.4.3 External Mechanical Integrity Testing

Lapis will perform an annual external mechanical integrity test (MIT). A temperature log or tracer survey will be used to monitor for mechanical integrity.

All logs recorded during the external MIT will be submitted to the Commissioner within 30 days of log-run completion.

5.4.4 Pressure Falloff Testing

Lapis will perform a required pressure falloff test at the end of every injection stage or every 5 years, whichever is more frequent. The bottomhole pressure gauge installed in the injection tubing will be utilized to measure the natural pressure decay after injection ceases in each stage. When a pressure falloff test is conducted in an injection stage and injection continues in that stage after the test, the test procedure in *Section 5.4.4.1* would be followed. This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

Monitoring of the final injection stage, which is closest to the upper confining zone (UCZ) and USDW, will continue in each injection well throughout the post-injection monitoring period. Real-time continuous monitoring will be accomplished utilizing the tubing-deployed tubing encapsulated conductor (TEC) and bottomhole pressure gauges.

5.4.4.1 <u>Testing Method</u>
The CO_2 injection rate and pressure will be held as constant as possible prior to the beginning of the falloff test, and data will be continuously recorded during testing. After the well is shut in, continuous pressure measurements will be taken with a downhole pressure gauge installed in the tubing string. The falloff period will end once the pressure-decay data plotted on a semi-log plot is a straight line, indicating that radial-flow conditions have been reached.

5.4.4.2 <u>Analytical Methods</u>
Near-wellbore conditions, such as the prevailing flow regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by comparing pressure falloff tests performed prior to initial injection with later tests. The effects of two-phase flow effects will also be considered. These well parameters resulting from falloff testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

All pressure falloff test results will be submitted to the IMD within 30 days of test completion.

5.4.4.3 Quality Assurance/Quality Control

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.5 Cement Evaluation and Casing Inspection Logs

A cement bond log will be run after the casing installation and the required cement-hardening time, to understand the cement's quality. A multi-finger caliper log will establish the initial shape of the inner wall of the long string casing after it is cemented. Following the installation of the completion equipment, including the tubing and packer assembly, an initial electromagnetic through-tubing casing inspection log (CIL) will be run. This log is sensitive to the conditions of the casing behind the tubing. The CIL will serve as the baseline survey for potential future repeat surveys, with the objective of detecting and localizing the potential loss of metal mass. These repeat electromagnetic CILs will only be performed if one of the following occurs:

- Other monitoring measurements create concern about the integrity of each well's casing, and the technical determination is made that a repeat CIL is most suitable to address those concerns. Examples include a loss of annulus pressure, or anomalous distributed noise and temperature measurements using the fiber optic cables installed in the wells.
- The Commissioner requests it.

Changes in the recorded electromagnetic response in such a repeat CIL can be analyzed to identify and localize casing corrosion.

5.5 Monitoring Programs

The CO_2 movement will be monitored for the life of the Libra project, including post-injection: from the CO_2 properties entering the proposed injection wells down to permanent containment of the CO_2 underground. All continuous recording devices located at the wellsite will be weatherproof or housed in weatherproof enclosures. In addition to the other reporting requirements, the raw data from these devices will be submitted in digital format along with other normally scheduled reports.

5.5.1 Continuous Injection Stream Physical Monitoring

Lapis will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure. A Supervisory Control and Data Acquisition (SCADA) system facilitates the operational data collection and monitoring for the full sequestration site, consisting of the pipeline, the injection wells, and the above-zone monitoring (AZM) monitoring well.

The injected CO_2 stream pressure will be continuously monitored in the CO_2 piping near the pipeline-wellhead interface. The annulus pressure and fluid volume added to the annulus will also be continuously recorded at the wellhead. A flow meter will measure the flow rate in the pipeline that connects to the injection wells. Each of the injection wells will also have its own flow meter to quantify the partitioning of the flow between the three injectors.

5.5.1.1 Analytical Methods

Lapis will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include an examination of trends to help determine a need for equipment maintenance or calibration. Semiannual reports of the monitoring data will be submitted to the Commissioner.

5.5.2 Continuous Injection Stream Composition Monitoring

Lapis will determine the chemical composition of the injection stream with the objective of understanding potential interactions between CO_2 and other injectate components, as well as with the wellbore materials. This determination is accomplished by quarterly sampling of the injection stream and subsequent laboratory analysis.

5.5.2.1 Sampling Methods

The quarterly measurements are obtained by extracting samples from the injection stream at a location where the composition is representative for the injection wells. The samples are subsequently sent to a laboratory for analysis.

5.5.2.2 Parameters Measured

Table 5-1 lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-1 – Injection Stream Measurements

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges in pipeline and downhole
pH	Quarterly	Lab analysis
Water (lb/MMscf)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis

Hydrogen Sulfide (ppm)	Quarterly	Lab analysis

*MMscf – million standard cubic feet
ppm – parts per million

5.5.3 Corrosion Coupon Monitoring

Monitoring of potential corrosion to the well tubing and casing materials will be conducted. A quarterly evaluation of the corrosion coupon monitoring system will be performed. Multiple coupons will be exposed to the stream composition to provide ongoing evaluation of materials compatibility. Results will be reported to the Commissioner semiannually.

5.5.3.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and long string casing, will be exposed to the conditions of the pipeline's CO_2 flow. The coupons will be removed on a quarterly schedule and examined for corrosion per American Society for Testing and Materials (ASTM) standards for corrosion-testing evaluation. The coupons, once removed, will be visually inspected for signs of corrosion and measured for weight and size. The corrosion rate will be estimated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4 Fluid Quality Monitoring

The USDW monitoring wells, Simoneaux USDW No. 1 and No. 2, will target the deepest USDW formation with an initial quarterly sampling frequency. This sampling frequency is for the pre-injection phase and will characterize any potential seasonal fluctuation in the USDW. This initial pre-injection sampling phase covers a minimum of 1 year until injection commences. After the initial phase, the sampling will become annual, with the optimal season of data collection determined by analysis of the first year of quarterly samples.

The AZM monitoring well, Simoneaux AZM No. 1 will provide complementary leakage-detecting monitoring measurements with fluid sampling capability, in the first permeable formation above the UCZ—referred to as the above-zone monitoring interval (AZMI). This interval has no expected seasonal variation. Therefore, sampling this formation—only if required from the start of the project—will provide sufficient resolution for analysis. A baseline sample will be taken in the AZMI before injection commences.

Table 5-2 summarizes the parameters analyzed and the planned sampling frequency, which apply to all USDW and AZM wells. Anomalous measurements will initiate further studies, including a more detailed analysis of existing data to understand the potential cause of the variation. This analysis could take the form of geochemical modeling and a review of trends observed in samples collected from all wells prior to the anomalous measurement.

These studies could also include integration with other measurements, such as AZMI pressure measurements and time-lapse seismic, as described in *Sections 5.5.6* and *5.5.8*, respectively. If all of these steps do not satisfactorily rule out the leakage scenario, further acquisition of contingency data will be considered. The options include acquiring another fluid sample to verify the original measurement, or taking complementary measurements—such as a repeat cased-hole wireline log in the injector(s). Details of the USDW and AZM sample-collection strategies are discussed in *Sections 5.5.5* and *5.5.6*, respectively.

Table 5-2 – USDW and AZM Monitoring Well Sampling Program During the Injection Phase

Parameter/Analyte	USDW Well Frequency	AZM Well Frequency
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	**Pre-injection:** Quarterly **After injection initiation**: Annually	Only if required by the Commissioner, or if warranted by a material change in other monitored parameters
Gas composition (CO_2, CH_4, C_{2+}, O_2, N_2)		
Dissolved cations (i.e., Ba, Ca, Fe, Mg, Mn, Na, other relevant metals)		
Dissolved anions (i.e., HCO_3 Br, Cl, F, SO_4)		

5.5.4.1 Analytical Methods

Lapis will test the fluid samples and maintain results for the parameters listed in Table 5-2. Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Material change in total dissolved solids (TDS)
- Material change in signature of major cations and anions
- Material increase in carbon dioxide concentration
- Material decrease in pH
- Material increase in concentration of injectate impurities
- Material increase in concentration of leached constituents

Testing results will be stored in an electronic database.

5.5.4.2 Laboratory to Be Used/Chain of Custody Procedures

The analysis of the fluid samples will be submitted to the IMD through a state-approved laboratory. Lapis will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.4.3 Quality Assurance and Surveillance Measures

Lapis will collect replicate samples and sample blanks for quality assurance/quality control

(QA/QC) purposes. The samples will be used to validate test results, if needed.

5.5.4.4 Plan for Guaranteeing Access to All Monitoring Locations

Placement of the well locations is optimized to be accessible from roads.

5.5.5 USDW Monitoring Wells

One well will be drilled first as a stratigraphic test well, which will be used to further verify the USDW depth. Two USDW monitoring wells will be drilled into the deepest USDW sand to support the Libra project. The deepest USDW formation is defined by salinity and is currently estimated to occur at a depth of approximately 1,222 feet (ft) from the Kelly bushing (1,203 (ft) from ground level) at the project site from a pick in the nearest offset well, the Waterford Oil Co. No. 001 (SN 81236). When the proposed injection wells, USDW monitoring wells, and stratigraphic test well are drilled, the USDW depth will be confirmed in each well through the collection of openhole wireline-resistivity logs.

The Simoneaux USDW No. 1 and Simoneaux USDW No. 2 monitoring wells will provide USDW-quality verification for the sequestration project. Hydrological modeling predicts that USDW flow is toward the northeast, which is why one of the USDW monitoring wells is placed in that direction. This monitoring well is therefore more likely to encounter CO_2 or its effects on the USDW chemistry if a leak does occur. Water samples will be collected from the USDW monitoring wells to monitor for signs of CO_2 or brine leakage. Figure 5-1 (*Section 5.5.5.1*) displays the monitoring well locations, which are also listed in Table 5-3 (also in *Section 5.5.5.1*).

5.5.5.1 Fluid Sampling Methods

Water samples will be collected from the USDW monitoring wells at the surface. The two well volumes will be purged to collect a pristine sample that represents the USDW water rather than water that has resided for a significant time in the wellbore. These water samples will be analyzed in the field for various physical parameters, including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity, as these parameters are sensitive to alteration over time. Additional analyses include TDS, concentrations of cations, anions, CO_2, and CH_4. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

The fluid-sampling parameters and frequencies for the groundwater monitoring wells were shown in Table 5-2, in *Section 5.5.4*, where details regarding sampling techniques and processes are also explained.

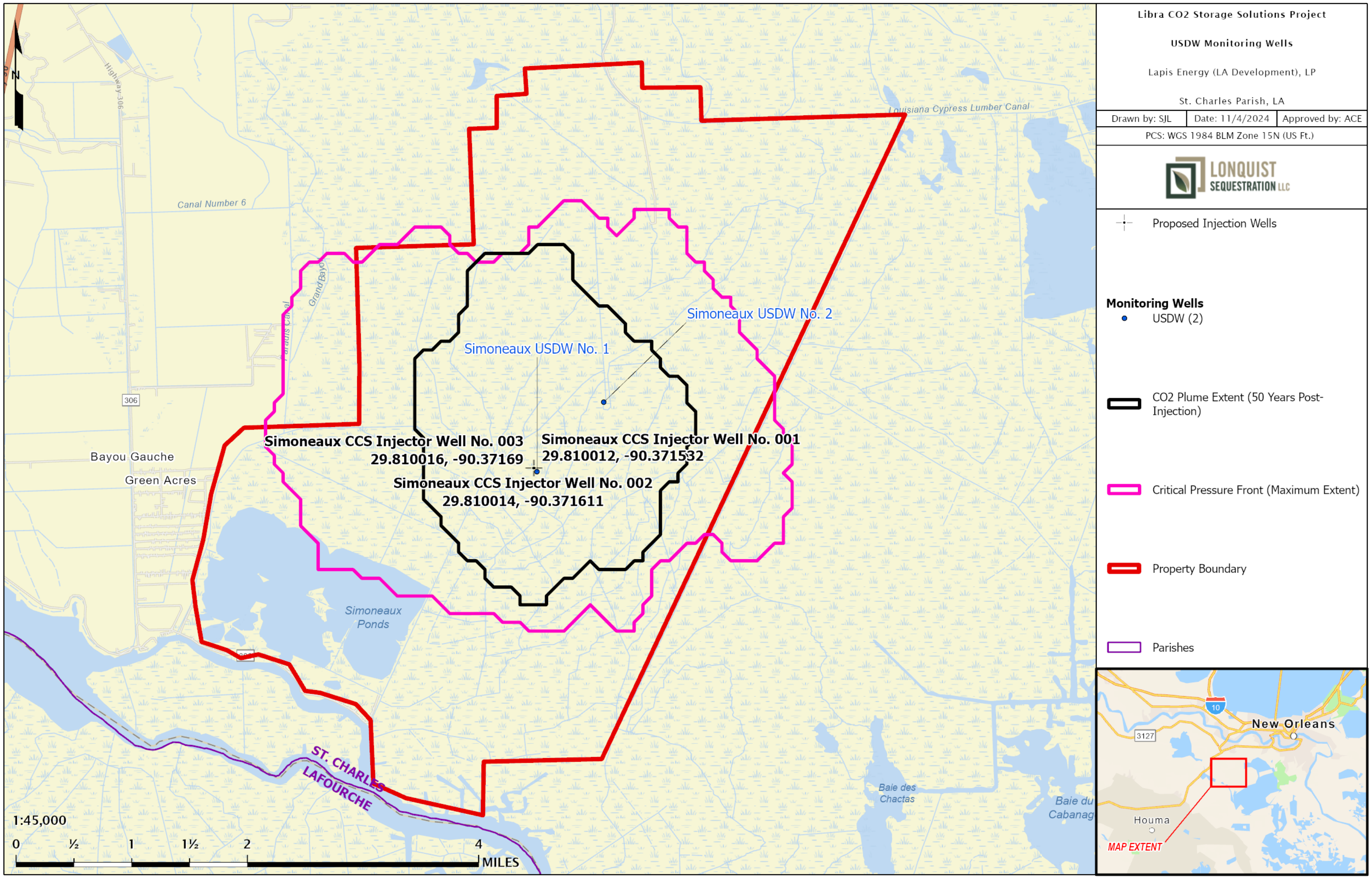


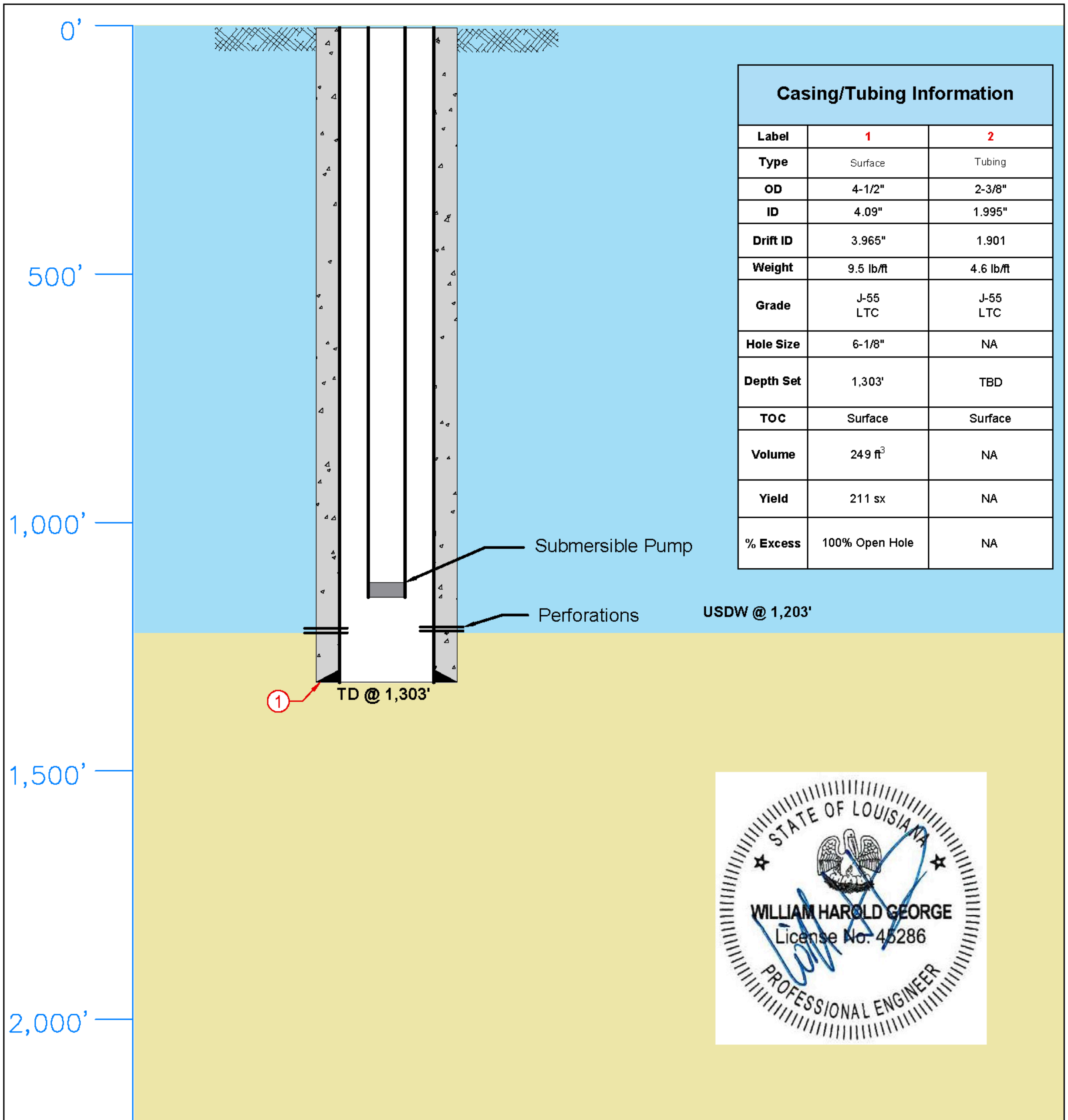
Figure 5-1 – Location of USDW Monitoring Wells

Table 5-3 – USDW Monitoring Well Details

Location Info	Simoneaux USDW No. 1	Simoneaux USDW No. 2
WGS84 X	2474000.5	2477049.1
WGS84 Y	10828674	10831842
WGS84 Latitude	29° 48' 33.804" N	29° 49' 4.476" N
WGS84 Longitude	90° 22' 15.7794" W	90° 21' 40.3554" W
NAD27 X	2,305,179.4'	2,308,272.0'
NAD27 Y	416,827.4'	419949.8'
NAD27 Latitude	29' 48' 33.819" N	29' 49' 04.471" N
NAD27 Longitude	90' 22' 15.764"W	90' 21 ' 40.359" W
Total Depth	1,303 ft	1,303 ft
Type	Vertical	Vertical

*WGS – World Geodetic System

Detailed wellbore schematics for both USDW monitoring wells are shown in Figures 5-2 and 5-3 (depth references are from ground level). Wellbore schematics of both USDW monitoring wells are also provided in *Appendix F*.

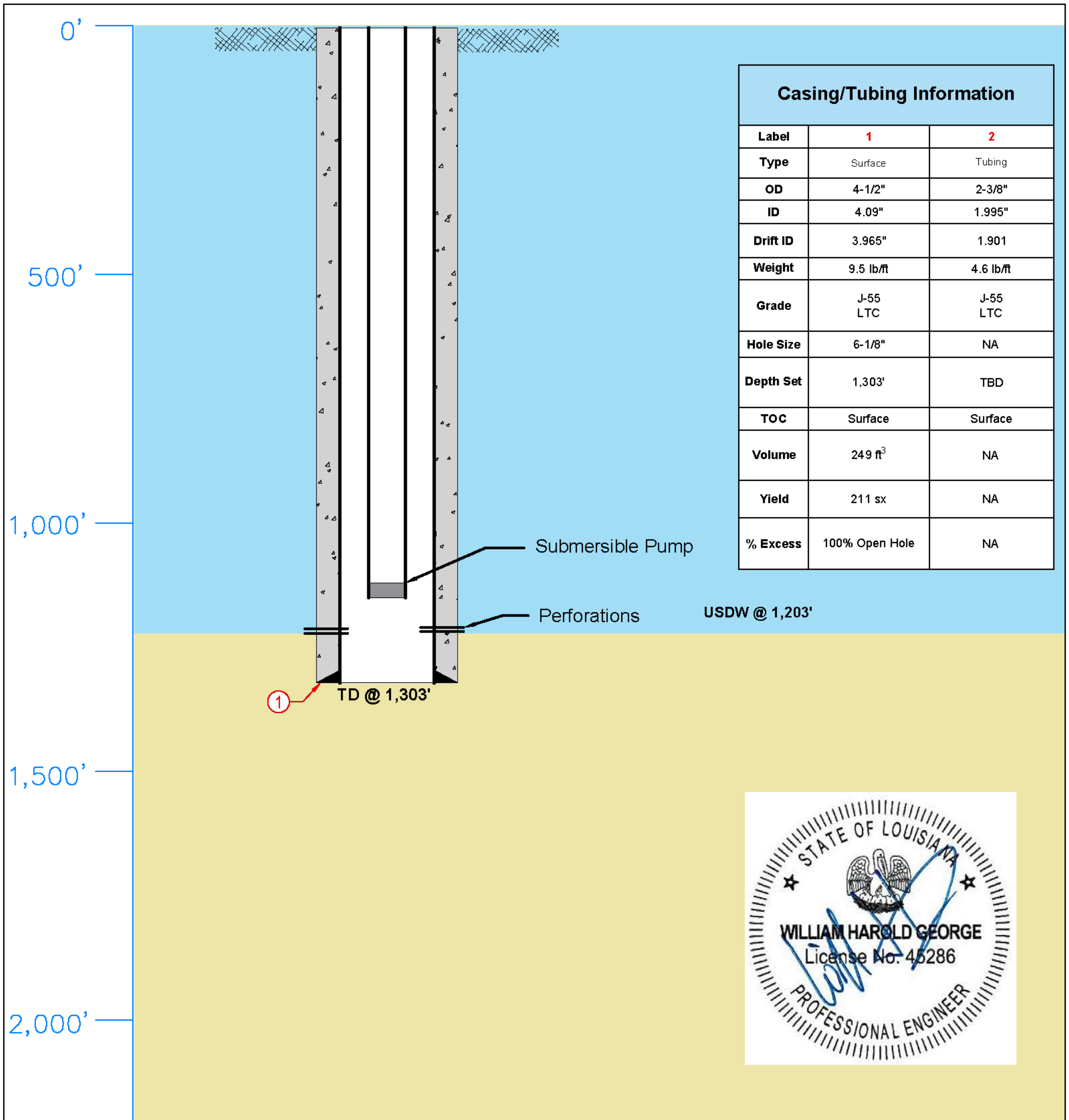


Casing/Tubing Information

Label	1	2
Type	Surface	Tubing
OD	4-1/2"	2-3/8"
ID	4.09"	1.995"
Drift ID	3.965"	1.901
Weight	9.5 lb/ft	4.6 lb/ft
Grade	J-55 LTC	J-55 LTC
Hole Size	6-1/8"	NA
Depth Set	1,303'	TBD
TOC	Surface	Surface
Volume	249 ft^3	NA
Yield	211 sx	NA
% Excess	100% Open Hole	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux USDW No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 15.764" W, 29º 48' 33.819" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 5-2 – Simoneaux USDW No. 1 Schematic



Casing/Tubing Information

Label	1	2
Type	Surface	Tubing
OD	4-1/2"	2-3/8"
ID	4.09"	1.995"
Drift ID	3.965"	1.901
Weight	9.5 lb/ft	4.6 lb/ft
Grade	J-55 LTC	J-55 LTC
Hole Size	6-1/8"	NA
Depth Set	1,303'	TBD
TOC	Surface	Surface
Volume	249 ft^3	NA
Yield	211 sx	NA
% Excess	100% Open Hole	NA

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux USDW No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 21' 40.359" W, 29º 49' 04.471" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 5-3 – Simoneaux USDW No. 2 Schematic

5.5.6 AZM Monitoring Well

To reduce the surface environmental impact of the sensitive wetlands area, the stratigraphic test well will be converted to a monitoring well at a depth corresponding to the AZMI (i.e., the first permeable formation above the UCZ) to support the Libra project. Simoneaux AZM No.1 will be located on Lapis' property—as shown in Figure 5-4, with the location details provided in Table 5-4—to the north of the injection wells, placed in between the injection well locations and the legacy wellbores. The well will serve as an early detection source of plume leakage out of the confining zone.

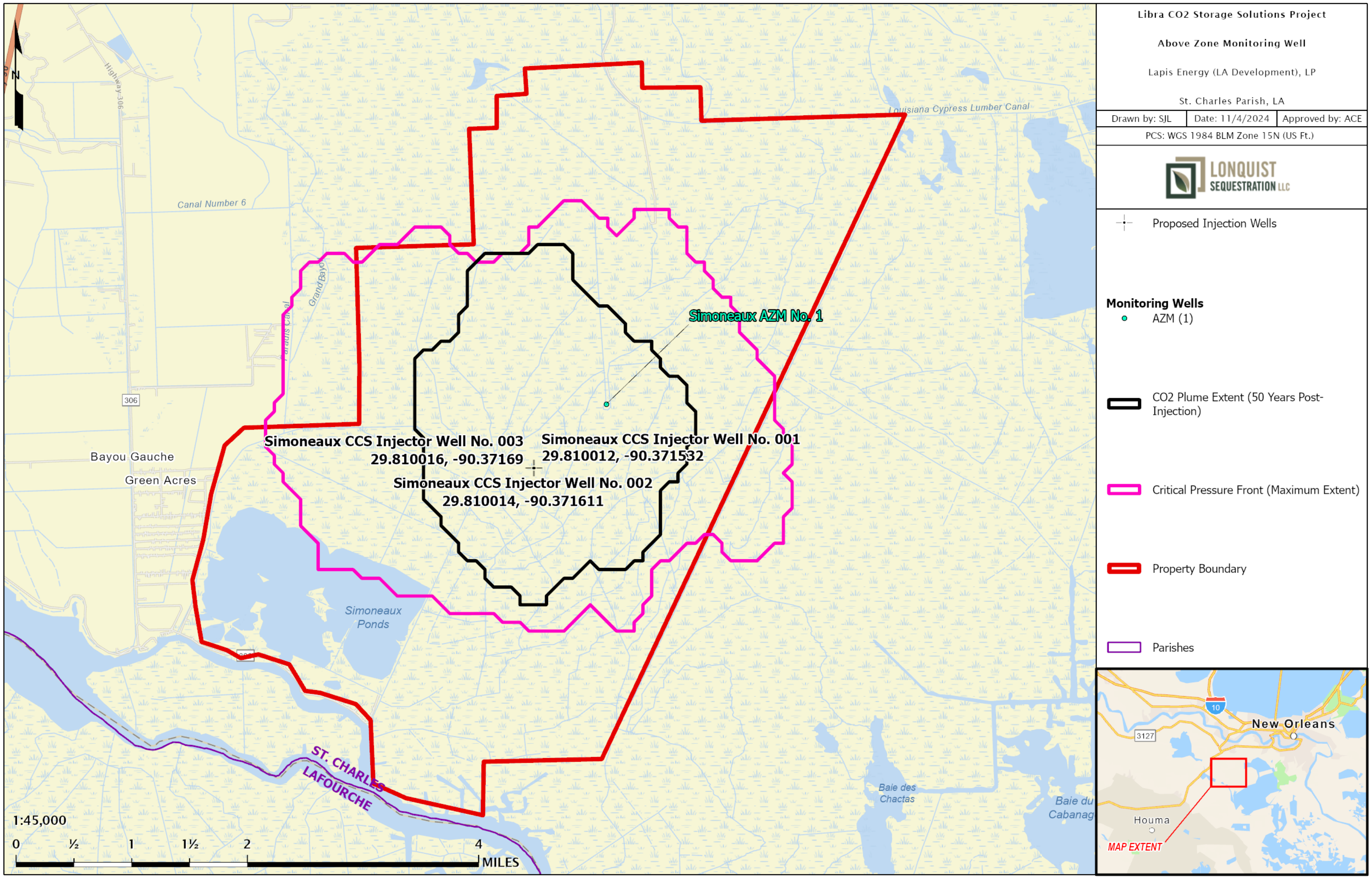


Figure 5-4 – Simoneaux AZM No. 1 Location

Table 5-4 – Location of Simoneaux AZM No. 1

Location Info	Simoneaux AZM No. 1
WGS84 X	2477156.70
WGS84 Y	10831747.00
WGS84 Latitude	29° 48' 59.2194" N
WGS84 Longitude	90° 21' 39.42" W
NAD27 X	2,308,378.1'
NAD27 Y	419,853.3'
NAD27 Latitude	29' 49' 03.506" N
NAD27 Longitude	90' 21' 39.164"W
Total Depth	10,250 ft (PBTD 3,170 ft)
Type	Vertical

*PBTD – Plugged-back total depth

5.5.6.1 Pressure/Temperature Monitoring

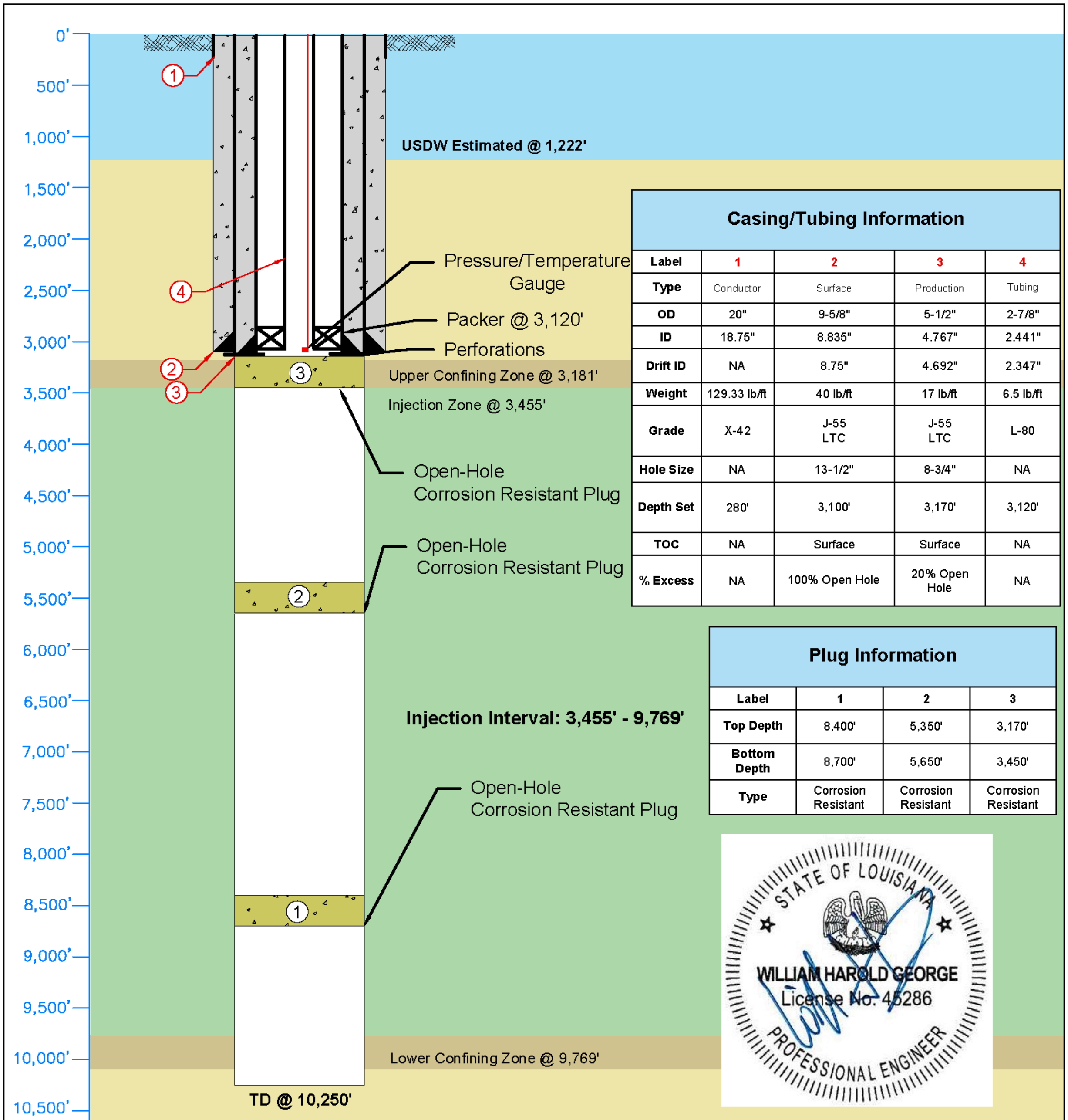
Although not required by Class VI regulations, Lapis will continuously monitor the pressure and temperature of the first permeable formation identified above the UCZ in Simoneaux AZM No. 1 using a downhole pressure-temperature gauge. Material deviations from baseline pressures after the start of injection will initiate further review in the area. This review will include a study to rule out any minor poroelastic pressure responses caused by compression from physical expansion of the injection interval. This benign response can occur without a physical leak path being present.

5.5.6.2 Fluid Sampling Methods

Simoneaux AZM No. 1 will be designed to allow fluid samples to be obtained if necessary. The fluid will be analyzed for the physical parameters and geochemical species provided in Table 5-2.

A baseline sample collection will occur before the start of injection, to characterize the original chemical composition of the formation fluids. As discussed in *Section 5.5.4*, unexpected changes in the fluid chemistry in the AZMI may be caused by leakage or other processes—and would result in further studies to determine if a leak is present.

A detailed wellbore schematic for Simoneaux AZM No. 1 is shown in Figure 5-5, the well is referenced to ground level, and also displayed in *Appendix F*.



Casing/Tubing Information

Label	1	2	3	4
Type	Conductor	Surface	Production	Tubing
OD	20"	9-5/8"	5-1/2"	2-7/8"
ID	18.75"	8.835"	4.767"	2.441"
Drift ID	NA	8.75"	4.692"	2.347"
Weight	129.33 lb/ft	40 lb/ft	17 lb/ft	6.5 lb/ft
Grade	X-42	J-55 LTC	J-55 LTC	L-80
Hole Size	NA	13-1/2"	8-3/4"	NA
Depth Set	280'	3,100'	3,170'	3,120'
TOC	NA	Surface	Surface	NA
% Excess	NA	100% Open Hole	20% Open Hole	NA

Plug Information

Label	1	2	3
Top Depth	8,400'	5,350'	3,170'
Bottom Depth	8,700'	5,650'	3,450'
Type	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux AZM No. 001	
	Country: USA	State/Province: Louisiana	County/Parish: St. Charles
	Location: 90° 21' 39.164" W, 29° 49' 03.506" N (NAD 27)	District:	Survey:
	API No:	Field:	Well Type/Status:
Louisiana License EF-7423	Serial No: TBD	Project No: LS169	Date: 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Connor Lofton	Reviewed: Andrew Ellis	Approved: William H. George, P.E.
	Rev No: 1	Notes:	

Figure 5-5 – Simoneaux AZM No. 1 Schematic

5.5.7 Injection Interval Monitoring

The injection interval will be monitored through measurements taken from the injection wells themselves. Each well will continuously monitor pressure and temperature in the current injection stage of the injection interval. Each stage will continue to be monitored for the life of the wells, which includes the final stage during the PISC period.

5.5.8 Injection Plume Monitoring

Lapis proposes the following two-tiered system for plume and pressure front tracking. Plume calculations based on continuously recorded pressures and temperatures will be used as a direct monitoring approach. The seismic sources and survey stations strategically positioned across the Libra project area will be used as recording devices—to indirectly monitor the plume with time-lapse seismic imaging, using sparse, permanent seismic monitoring technology.

- Direct method, targeting injection zone pressure: using the downhole pressure gauges installed in the injection wells

- Indirect method, targeting CO_2 presence: sparse permanent seismic monitoring (SPSM)

This two-tiered system will serve two purposes: first, to verify reservoir conditions during injection; and second, to track plume migration and validate the plume model. Continuous pressure and temperature monitoring of the injection reservoir will allow for continuous monitoring of the reservoir conditions and calculations. The actual plume migration will be determined by a combination of SPSM measurements and model history matching of the direct plume measurements. An adequate baseline of the SPSM system will be run prior to injection initiation, and monitoring will occur regularly during the injection period—the timing of which is discussed in detail in *Section 5.5.8.2.*

5.5.8.1 Direct Monitoring: Pressure

The injection wells will be instrumented with a downhole pressure gauge to continuously monitor the bottomhole pressure in the injection interval. The pressure response recorded by any gauge would not only be a representation of the injection through that well but may also be affected by the far-field pressure response from the other injection wells.

The dynamic model built during the site-evaluation phase may be used to predictively monitor the reservoir conditions during injection operations. Continual monitoring of bottomhole pressures and temperatures, combined with known reservoir parameters, will be used to derive reservoir conditions throughout the life of the project.

Any periods of shut-in of the well can be observed and treated as a falloff test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continual measurements obtained during regular operating conditions, will aid in updating models and forecasts.

5.5.8.2 Indirect Monitoring: Sparse Permanent Seismic Monitoring

Lapis will use time-lapse SPSM technology as the primary method to indirectly monitor the CO_2 plume extent and development, to meet the operation monitoring requirements.

The areal distribution of the CO_2 plume in the injection zones will be determined using a time-lapse ray path seismic technique. Substitution of CO_2 for brine within sandstones and limestones at similar project depths is well documented to produce a strong change in acoustic impedance (Vasco et al., 2019). Leading-edge techniques for time-lapse imaging of CO_2 plumes developed during implementation of the Regional Department of Energy (DOE) Partnership projects include time-lapse vertical seismic profiling (Daley, 2006; Gupta et al., 2020), azimuthal vertical seismic profiling (Gordon et al., 2016), and sparse array walk-away surveys or scalable, automated, semipermanent seismic array (SASSA) (Roach et al., 2015; Burnison et al., 2016; Livers, 2017).

Lapis is proposing the deployment of one or more autonomous, permanent sources and a sparse receiver seismic array within and beyond the expected dimensions of the CO_2 plume. The receivers will be installed subsurface around the project area and will be used to monitor ray paths that allow for dense (high-fold) sampling over time.

System flexibility allows for sensors and/or source geometry to be optimally redeployed further away from the injection wells as the plume becomes larger. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve the differences between the surveys, which will be mapped to show the change in the plume extent over time. The seismic array will monitor the plume growth via a grid of several tens of surface recorders at different "X-Y" locations, resembling a grid of "pseudo-monitoring well locations" in the form of a single seismic trace per X,Y location—repeated regularly and aimed at detecting the moment a plume reaches an X,Y location. The X,Y locations of the seismic measurement locations will surround the injectors and allow monitoring of the plume expansion in all directions. The final locations of the source and the receiver locations will be based on a ray-tracing exercise, to determine what areas can be illuminated by the seismic rays.

A sparse, permanent seismic monitoring system has an additional benefit in that it minimizes the incremental surface disturbance in the wetlands. One or more seismic sources will be located on or near the injection well pad.

Baseline Survey

Conducting a quality baseline survey is critical, because it is the only opportunity to capture an image of the reservoir before injection operations or offset activity—either natural or man-made—impact it. Without this survey, the future interpretation of formation changes cannot be assessed. Also, the size of the baseline survey constrains the extent of the initial plume growth measurement ability. It is essential to acquire a baseline survey with sufficient coverage if the initial reservoir models are not accurately forecasting plume migration. As the plume grows, additional receivers and sources can be installed, if necessary, as long as a baseline can be taken for the new X,Y imaging locations, ahead of the plume encroachment.

In the unlikely case that the SPSM technology proves to be impractical (e.g., in terms of installation, maintenance, or actual plume monitoring), Lapis will—in consultation with and approval of the LDENR—revert back to an alternative seismic monitoring method (e.g., 2D (4D) seismic and/or 4D walk-away vertical seismic profiles).

5.5.8.3 Equipment Design and Setup

The proposed equipment for periodic survey operations to determine the CO_2 plume growth over time includes the time-lapse SPSM, which uses at least one active source and several tens of surface recorders strategically placed across the project area.

5.5.8.4 Equipment Overview

This section discusses the typical hardware setup and use of in situ monitoring equipment for temperature, pressure, and seismic data. The equipment described is representative of the technology that will be employed. Specific vendor-proprietary equipment details will be provided when the vendor is selected nearer to the time the well is drilled.

Tubing Encapsulated Conductor

The TEC is a proven technology that the oil and gas industry has used reliably for more than 25 years. It is installed to electrically support the quartz pressure/temperature (QPT) gauges and is designed for prolonged life in the most hostile downhole environments. The primary function of the TEC is to transmit electronic digital signals and power between subsurface components and a surface interface module used to conduct reservoir management. An encapsulation material specially designed with safe removal components can be—and is recommended to be—extruded over the TEC, thereby adding a layer of protection to the metal sheath from abrasion while running downhole. Figure 5-6 illustrates the TEC design.

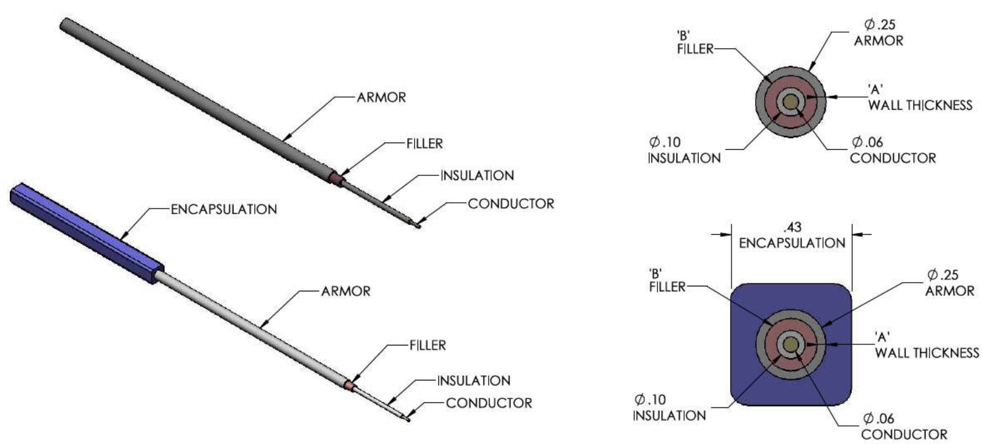


Figure 5-6 – TEC Illustration

Quartz Pressure/Temperature Gauge

Quartz pressure/temperature gauges measure static and dynamic pressures and temperatures. Only two fittings (the pressure port and the TEC) are required to interface the gauge (Figure 5-7) with the carrier. The fittings can be externally tested in the direction that they will experience pressure, thereby eliminating the need for an internal pressure-test tool.

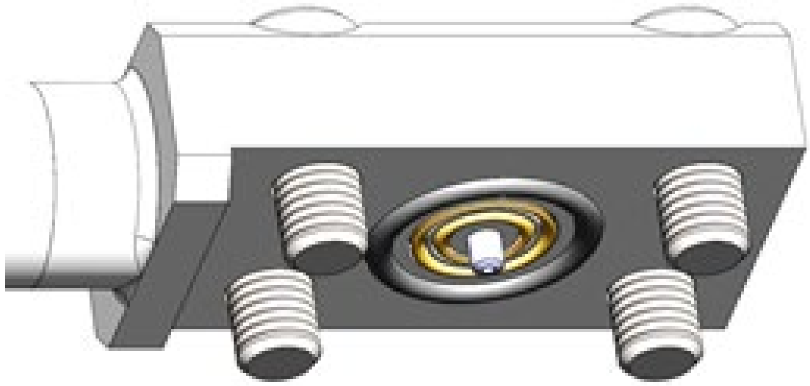


Figure 5-7 – External QPT Gauge Illustration

5.5.9 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy SWO 29-N-6 **§3625.A** [40 CFR **§146.90**]. Reporting and reevaluation requirements will be executed by Lapis for the life of the Libra project, including post-injection. Monitoring strategies are included for the injection stream composition and wellhead CO_2 conditions using pressure and temperature gauges as well as mass flowmeters, to allow for continuous data reading. Bottomhole operating parameters are monitored by the pressure gauges installed on the injection tubing. Well integrity is confirmed by the execution of annual tests. Above-zone confinement is monitored by the AZM monitoring well equipped with pressure sensors and periodic fluid sampling. The lowermost USDW is monitored for any changes in chemical composition at two USDW monitoring wells. This comprehensive monitoring plan ensures the ultimate protection of the USDW in the project area.

A significant part of the plan is the indirect monitoring and tracking of the injected CO_2 in the subsurface. The time-lapse SPSM surveys are indirect measurements of changes in the injection formation. Such surveys are sensitive to both the presence of CO_2 and, to a lesser extent, the formation pressure. The SPSM will act as the indirect monitoring strategy for the project.

The contents of this plan will be carried out during the entirety of the life of the injection wells, including post-injection monitoring—following a predetermined timeline based on both updated plume growth and observed well conditions at the time of planned injection cessation.

Table 5-5 summarizes the various measurements discussed in the Testing and Monitoring Plan during the injection period. Measurements and their frequency for the PISC are provided in *Section 7 – Post-Injection Site Care and Site Closure Plan*.

Table 5-5 – Testing and Monitoring Plan Measurements

Equipment / Measurement	Regulation	Comment	Frequency
Flow Meter	**§3625.A.2 §146.90(b)**	Measures mass flow rate	Continuously
Corrosion Coupon	**§3625.A.3 §146.90(c)**	Measures corrosion levels on the types of metal used in the project	Quarterly
Injection Stream Sampling	**§3625.A.1 §146.90(a)**	Provides more detailed analysis via periodic lab analysis of injection stream	Quarterly
Injector Wellhead Tubing Pressure Gauge	**§3625.A.1 §146.90(a)**	Verifies surface injection pressure	Continuously
Injector Wellhead Annulus Pressure Gauge	**§3625.A.2 §146.90(b)**	Verifies annulus pressure maintained	Continuously
Injector Annulus Pressure Test	**§3627.A.2 §146.89(b)**	Verifies absence of leak in annulus	Annually
Injector Downhole QPT Gauges	**§3625.A.2 §146.90(b)**	Measures downhole pressure and temperature (P/T) as close as possible to the formation (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	§3625.A.6 §146.90(f)	Bottomhole pressure gauge used for the pressure falloff test	At the end of every injection stage or every 5 years, whichever is more frequent
Sparse Permanent Seismic Monitoring System	**§3625.A.7.b §146.90(g)(2)**	SPSM: time-lapse seismic surveying system	At least monthly
Injector Casing Inspection Log	**§3625.A.5 §146.90(e)**	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey only in case there is a concern about leakage or if the regulator requests

Equipment / Measurement	Regulation	Comment	Frequency
AZM Monitoring Well Downhole Pressure / Temperature Gauge	Redundant measurement, no direct regulatory link	Potential to detect pressure anomaly in AZMI in case of leakage; will require careful analysis due to false positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously
AZM Monitoring Well Fluid Sampling	**§3625.A.4 §146.90(d)**	Above UCZ fluid collection is possible if other trends justify reasonability.	Only if required
USDW Fluid Sampling	**§3625.A.4 §146.90(d)**	Sample fluids from the deepest USDW, as recommended by guidelines, and analyze composition.	At least once every 5 years
Function Testing Emergency Shut Down Systems	**§3621.A.7.c**	function-test all critical systems of control and safety	Every 6 months

The following attachments are located in *Appendix F*:

- Appendix F-1 USDW Monitoring and AZM Wells Plan Map
- Appendix F-2 Simoneaux USDW No. 1 Schematic
- Appendix F-3 Simoneaux USDW No. 2 Schematic
- Appendix F-4 Simoneaux AZM No. 1 Schematic

5.6 References

Burnison, S. A., Livers, A. J., Hamling, J. A., Slaako, O., and Gorecki, C. D., 2016, Design and implementation of a scalable, automated, semi-permanent seismic array for detecting CO2 extent during geologic CO2 injection: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland, p. 3879- 3888.

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SECTION 6 – INJECTION WELL PLUGGING PLAN

TABLE OF CONTENTS

Figures

Tables

6.1 Introduction

The Lapis Energy (LA Development), LP (Lapis) Libra CO_2 Storage Solutions Project (Libra) plugging plans for Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003 are designed to satisfy the requirements of Statewide Order (SWO) 29-N-6, **§3631** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.92**]. This section provides details on the plans for the completion and plugback, as well as the plugging and abandonment (P&A) procedures for the proposed injection wells. The section also outlines the P&A plans and procedures for the Underground Source of Drinking Water (USDW) monitoring and the above-zone monitoring (AZM) wells. For all wells in the project once final plugging is complete Lapis will submit a closure report to the Commissioner within 30 days of the final P&A.

6.2 Injection Well Final Plugging and Abandonment

Once the injection period for a stage is complete in each of the proposed injection wells, a plug will be set in that well to isolate the perforations, and the next completion stage will be perforated. This process will be repeated until each of the completion intervals has been fully developed, and the gross injection interval has been fully completed. Once the injection period is complete, the perforated intervals will be isolated, and the monitoring process of the gross injection zone will continue.

When the monitoring phase is complete, and the regulators approve of project cessation, the injection and monitoring wells will be permanently plugged and abandoned. The plugging procedures and operations to be performed will ensure that CO_2 is confined to the injection zone and that compatible materials will be installed to prevent CO_2 or formation fluids from migrating out of the injection zone.

6.2.1 Final Plugging and Abandonment

After injection operations are complete and the pore space of the formation has been utilized, the injection wells will be prepared for final P&A. The general procedure includes the following.

6.2.1.1 Pre-Plugging Activities

1. Notice of Intent to Plug will be communicated to the Louisiana Department of Energy and Natural Resources (LDENR) by submitting Form UIC-17 with detailed plans. No actual well-plugging operations will commence until written approval from the Commissioner of Conservation (Commissioner) is received.
2. Downhole pressure gauges installed on the backside of the injection tubing will be used to measure the injection interval reservoir pressure.
3. Mechanical integrity of the tubing-casing annulus will be demonstrated by pressure testing, as described in *Section 5 – Testing and Monitoring Plan*.
4. The wellbore will be flushed with a buffer fluid and be in static equilibrium with the appropriate mud weight.

5. Casing inspection and cement bond logs will be performed prior to final plugging. Log evaluation will determine if the plugging procedure needs to be revised.

6.2.1.2 Plugging Activities for Simoneaux CCS Injector Well No. 001

Introduction: This procedure covers the permanent P&A of Simoneaux CCS Injector Well No. 001 at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed to abandon the perforations. A series of plugs will then be set to secure the confining zone, surface casing shoe, USDW, and surface. Finally, the wellhead will be removed and the site left for full reclamation.

Procedure:

1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. Nipple down (N/D) the wellhead and nipple up (N/U) the blowout preventers (BOPs).
4. Pull and lay down 4 ½ inch (in.) tubing.
5. Run in hole with the junk basket and gauge ring for 7-in. casing to the packer at 7,990 feet (ft).
6. Set the cement retainer above the packer at 7,990 ft.
7. Trip in hole with the work string, stab into the cement retainer, and establish injection.
8. Squeeze the perforations with 94 cubic ft of cement (14.13 pounds per gallon (ppg) of acid-resistant blend).
9. Pull out of the retainer and spot 21.5 cubic ft (100 ft) of cement on top of the retainer.
10. Pull above the cement and circulate the work string clean.
11. Tag and test the cement/cement retainer to 500 pounds per square inch (psi) for 30 minutes.
12. Pull out of hole with the work string.
13. Run in hole with the junk basket and gauge ring for 7-in. casing to 3,605 ft.
14. Set the corrosion-resistant alloy (CRA) cast iron bridge plug (CIBP) in 7-in. casing at 3,605 ft.
15. Trip in hole with the work string to 3,605 ft.
16. Mix and spot a balanced plug with 98 cubic ft of cement (14.13 ppg of acid-resistant blend).
    a. Top of cement (TOC) = 3,150 ft
17. Pull above the cement and circulate the work string clean.
18. Tag and test the cement/CIBP to 500 psi for 30 minutes.
19. Pull out of hole with the work string.
20. Run in hole with the junk basket and gauge ring for 7-in. casing to 1,303 ft.
21. Set the CIBP in 7-in. casing at 1,303 ft.
22. Trip in hole with the work string to 1,303 ft.
23. Mix and spot a balanced plug with 43 cubic ft of cement (16.4 ppg of Class H).

24. Pull above the cement and circulate the work string clean.
25. Tag and test the cement/CIBP to 500 psi for 30 minutes.
26. Pull out of hole with the work string.
27. Run in hole with the junk basket and gauge ring for 7-in. casing to 50 ft.
28. Set the CIBP in 7-in. casing at 50 ft.
29. Trip in hole with the work string to 50 ft.
30. Mix and spot 11 cubic ft of cement (16.4 ppg of Class H).
31. Pull and lay down the remaining work string.
32. Confirm the cement at surface.
33. Secure the well. Cut the casing 6 ft below the ground line and weld a plate on top of the casing with required well identification information.
34. Rig down and move out (RDMO) the equipment.

6.2.1.3 Plugging Activities for Simoneaux CCS Injector Well No. 002

Introduction: This procedure covers the permanent P&A of Simoneaux CCS Injector Well No. 002 at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed to abandon the perforations. A series of plugs will then be set to secure the confining zone, surface casing shoe, USDW, and surface. Finally, the wellhead will be removed and the site left for full reclamation.

Procedure:

1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. N/D the wellhead and N/U the BOPs.
4. Pull and lay down 4 ½ in. tubing.
5. Run in hole with the junk basket and gauge ring for 7-in. casing to the packer at 6,650 ft.
6. Set the cement retainer above the packer at 6,650 ft.
7. Trip in hole with the work string, stab into the cement retainer, and establish injection.
8. Squeeze the perforations with 53 cubic ft of cement (14.13 ppg of acid-resistant blend).
9. Pull out of the retainer and spot 21.5 cubic ft (100 ft) of cement on top of the retainer.
10. Pull above the cement and circulate the work string clean.
11. Tag and test the cement/cement retainer to 500 psi for 30 minutes.
12. Pull out of hole with the work string.
13. Run in hole with the junk basket and gauge ring for 7-in. casing to 3,605 ft.
14. Set the CRA CIBP in 7-in. casing at 3,605 ft.
15. Trip in hole with the work string to 3,605 ft.
16. Mix and spot a balanced plug with 98 cubic ft of cement (14.13 ppg of acid-resistant blend).
    a. TOC = 3,150 ft
17. Pull above the cement and circulate the work string clean.
18. Tag and test the cement/CIBP to 500 psi for 30 minutes.
19. Pull out of hole with the work string.
20. Run in hole with the junk basket and gauge ring for 7-in. casing to 1,322 ft.

21. Set the CIBP in 7-in. casing at 1,303 ft.
22. Trip in hole with the work string to 1,303 ft.
23. Mix and spot a balanced plug with 43 cubic ft of cement (16.4 ppg of Class H).
24. Pull above the cement and circulate the work string clean.
25. Tag and test the cement/CIBP to 500 psi for 30 minutes.
26. Pull out of hole with the work string.
27. Run in hole with the junk basket and gauge ring for 7-in. casing to 50 ft.
28. Set the CIBP in 7-in. casing at 50 ft.
29. Trip in hole with the work string to 50 ft.
30. Mix and spot 11 cubic ft of cement (16.4 ppg of Class H).
31. Pull and lay down the remaining work string.
32. Confirm the cement at surface.
33. Secure the well. Cut casing 6 ft below the ground line and weld a plate on top of the casing with required well identification information.
34. RDMO the equipment.

6.2.1.4 Plugging Activities for Simoneaux CCS Injector Well No. 003

Introduction: This procedure covers the permanent P&A of Simoneaux CCS Injector Well No. 003 at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed to abandon the perforations. A series of plugs will then be set to secure the confining zone, surface casing shoe, USDW, and surface. Finally, the wellhead will be removed and the site left for full reclamation.

Procedure:

1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. N/D the wellhead and N/U the BOPs.
4. Pull and lay down 4 ½ in. tubing.
5. Run in hole with the junk basket and gauge ring for 7-in. casing to the packer at 4,930 ft.
6. Set the cement retainer above the packer at 4,930 ft.
7. Trip in hole with the work string, stab into the cement retainer, and establish injection.
8. Squeeze the perforations with 87 cubic ft cement (14.13 ppg of acid-resistant blend).
9. Pull out of the retainer and spot 21.5 cubic ft (100 ft) of cement on top of the retainer.
10. Pull above the cement and circulate the work string clean.
11. Tag and test the cement/cement retainer to 500 psi for 30 minutes.
12. Pull out of hole with the work string.
13. Run in hole with the junk basket and gauge ring for 7-in. casing to 3,605 ft.
14. Set the CRA CIBP in 7-in. casing at 3,605 ft.
15. Trip in hole with the work string to 3,605 ft.
16. Mix and spot a balanced plug with 98 cubic ft of cement (14.13 ppg of acid-resistant blend).
    a. TOC = 3,150 ft
17. Pull above the cement and circulate the work string clean.

18. Tag and test the cement/CIBP to 500 psi for 30 minutes.
19. Pull out of hole with the work string.
20. Run in hole with the junk basket and gauge ring for 7-in. casing to 1,303 ft.
21. Set the CIBP in 7-in. casing at 1,303 ft.
22. Trip in hole with the work string to 1,303 ft.
23. Mix and spot a balanced plug with 43 cubic ft of cement (16.4 ppg of Class H).
24. Pull above the cement and circulate the work string clean.
25. Tag and test the cement/CIBP to 500 psi for 30 minutes.
26. Pull out of hole with the work string.
27. Run in hole with the junk basket and gauge ring for 7-in. to 50 ft.
28. Set the CIBP in 7-in. casing at 50 ft.
29. Trip in hole with the work string to 50 ft.
30. Mix and spot 11 cubic ft of cement (16.4 ppg of Class H).
31. Pull and lay down the remaining work string.
32. Confirm the cement at surface.
33. Secure well. Cut the casing 6 ft below the ground line and weld a plate on top of the casing with the required well identification information.
34. RDMO the equipment.

Tables 6-1 through 6-3 provide the details for well-construction materials to be removed for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003, respectively.

Table 6-1 – Description of Tubing and Other Well-Construction Materials to Be Removed, Simoneaux CCS Injector Well No. 001

Well Component	Size	Amount	Notes / Comments
Safety Injection Valve, Injection Tubing, Tubing Encapsulated Conductor (TEC) and Pressure/Temperature (PT) Gauge, and Packer Seal Assembly	4-1/2 in.	7,990 ft	Remove seal assembly from injection packer.

Table 6-2 – Description of Tubing and Other Well-Construction Materials to Be Removed, Simoneaux CCS Injector Well No. 002

Well Component	Size	Amount	Notes / Comments
Safety Injection Valve, Injection Tubing, TEC and PT Gauge, and Packer Seal Assembly	4-1/2 in.	6,650 ft	Remove seal assembly from injection packer.

Table 6-3 – Description of Tubing and Other Well-Construction Materials to Be Removed, Simoneaux CCS Injector Well No. 003

Well Component	Size	Amount	Notes / Comments
Safety Injection Valve, Injection Tubing, TEC and PT Gauge, and Packer Seal Assembly	4-1/2 in.	4,930 ft	Remove seal assembly from injection packer.

Tables 6-4 through 6-6 provide the plugging details for zonal isolation plugs for the three injection wells, respectively.

Table 6-4 – Plugging Details for Zonal Isolation Plugs, Simoneaux CCS Injector Well No. 001

Plug Description	
Plug Interval	**1**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.
Depth to Bottom of Tubing or Drill Pipe (MD)	9,182 ft
Barrels (bbls) of Cement to Be Used (each plug)	2
Slurry Volume to Be Pumped (cf)	11
Slurry Weight (lb/gal)	14.13
Top of Plug (MD)	9,132 ft
Bottom of Plug (MD)	9,182 ft
Type of Cement or Other Material	Retrievable Plug with Cement
Method of Emplacement	Wireline
New Plug?	Yes

*cf – cubic feet
lb/gal – pounds per gallon
MD – measured depth

Table 6-5 – Plugging Details for Zonal Isolation Plugs, Simoneaux CCS Injector Well No. 002

Plug Description	
Plug Interval	**1**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.
Depth to Bottom of Tubing or Drill Pipe (MD)	7,301 ft
Plug Description	
Plug Interval	**1**
Bbls of Cement to Be Used (each plug)	2
Slurry Volume to Be Pumped (cf)	11
Slurry Weight (lb/gal)	14.13
Top of Plug (MD)	7,251 ft
Bottom of Plug (MD)	7,301 ft
Type of Cement or Other Material	Retrievable Plug with Cement
Method of Emplacement	Wireline
New Plug?	Yes

Table 6-6 – Plugging Details for Zonal Isolation Plugs, Simoneaux CCS Injector Well No. 003

Plug Description	
Plug Interval	**1**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.
Depth to Bottom of Tubing or Drill Pipe (MD)	5,954 ft
Bbls of Cement to Be Used (each plug)	2
Slurry Volume to Be Pumped (cf)	11
Slurry Weight (lb/gal)	14.13
Top of Plug (MD)	5,904 ft
Bottom of Plug (MD)	5,954 ft
Type of Cement or Other Material	Retrievable Plug with Cement
Method of Emplacement	Wireline
New Plug?	Yes

Tables 6-7 through 6-9 then provide the plugging details for the cement plugs for the three injectors, respectively.

Table 6-7 – Plugging Details for Cement Plugs, Simoneaux CCS Injector Well No. 001

Plug Description	Zonal Isolation Plug	UCZ Plug	Surface Casing Shoe and USDW Plug	Surface Plug
Plug Number	**1**	**2**	**3**	**4**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.	6.276 in.	6.276 in.	6.276 in.
Depth to Bottom of Tubing or Drill Pipe (MD)	7,990 ft	3,605 ft	1,303 ft	50 ft
Sacks of Cement to Be Used (each plug)	91	77	40	10
Slurry Volume to Be Pumped (cf)	116	98	43	11
Slurry Weight (lb/gal)	14.13	14.13	16.4	16.4
Top of Plug (MD)	7,890 ft	3,150 ft	1,103 ft	0 ft
Bottom of Plug (MD)	8,429 ft	3,605 ft	1,303 ft	50 ft
Type of Cement or Other Material	Corrosion Resistant	Corrosion Resistant	Portland Cement	Portland Cement
Method of Emplacement	Squeeze	Circulation	Circulation	Circulation
Retainer/CIBP Depth	7,990 ft	3,605 ft	1,303 ft	50 ft
New Plug?	Yes	Yes	Yes	Yes

*UCZ – upper confining zone

Table 6-8 – Plugging Details for Cement Plugs, Simoneaux CCS Injector Well No. 002

Plug Description	Zonal Isolation Plug	UCZ Plug	Surface Casing Shoe and USDW Plug	Surface Plug
Plug Number	**1**	**2**	**3**	**4**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.	6.276 in.	6.276 in.	6.276 in.

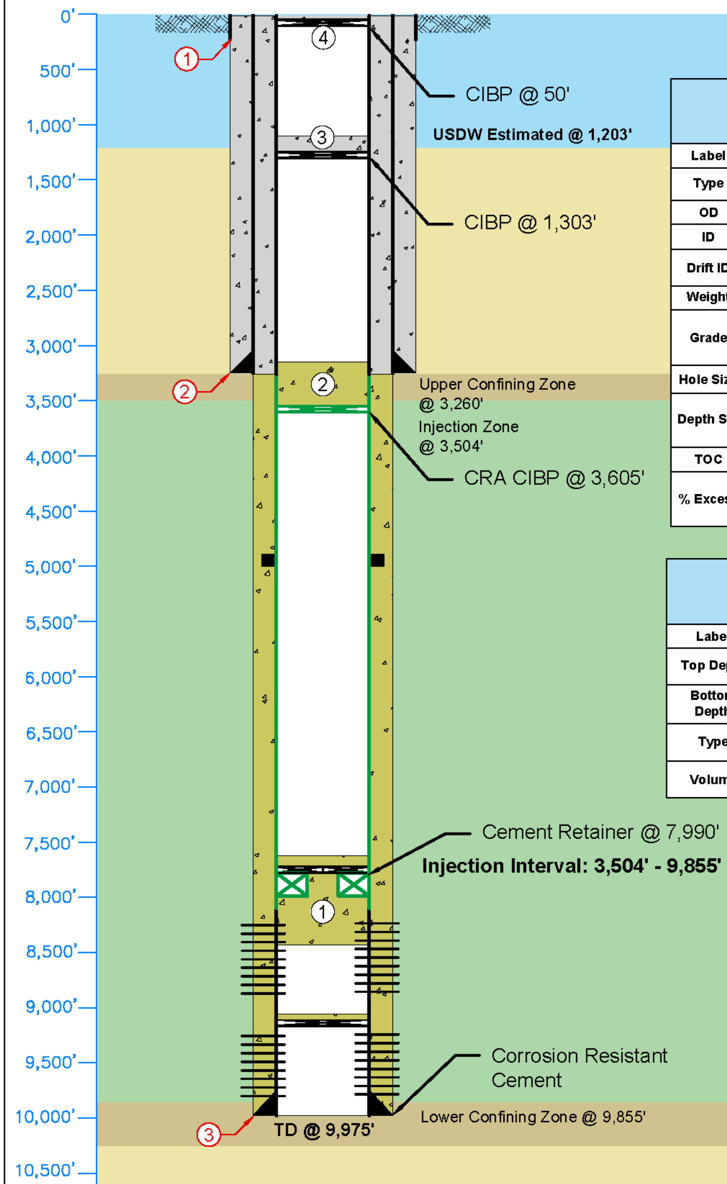
Depth to Bottom of Tubing or Drill Pipe (MD)	6,650 ft	3,605 ft	1,303 ft	50 ft
Sacks of Cement to Be Used (each plug)	59	77	40	10
Slurry Volume to Be Pumped (cf)	74	98	43	11
Slurry Weight (lb/gal)	14.13	14.13	16.4	16.4
Top of Plug (MD)	6,550 ft	3,150 ft	1,103 ft	0 ft
Plug Description	**Zonal Isolation Plug**	**UCZ Plug**	**Surface Casing Shoe and USDW Plug**	**Surface Plug**
Plug Number	**1**	**2**	**3**	**4**
Bottom of Plug (MD)	6,896 ft	3,605 ft	1,303 ft	50 ft
Type of Cement or Other Material	Corrosion Resistant	Corrosion Resistant	Portland Cement	Portland Cement
Method of Emplacement	Squeeze	Circulation	Circulation	Circulation
Retainer/CIBP Depth	6,650 ft	3,605 ft	1,303 ft	50 ft
New Plug?	Yes	Yes	Yes	Yes

Table 6-9 – Plugging Details for Cement Plugs, Simoneaux CCS Injector Well No. 003

Plug Description	Zonal Isolation Plug	UCZ Plug	Surface Casing Shoe and USDW Plug	Surface Plug
Plug Number	**1**	**2**	**3**	**4**
Diameter of Boring in Which Plug Will Be Placed	6.276 in.	6.276 in.	6.276 in.	6.276 in.
Depth to Bottom of Tubing or Drill Pipe (MD)	4,930 ft	3,605 ft	1,303 ft	50 ft
Sacks of Cement to Be Used (each plug)	85	77	40	10
Slurry Volume to be Pumped (cf)	108	98	43	11
Slurry Weight (lb/gal)	14.13	14.13	16.4	16.4
Top of Plug (MD)	4,830 ft	3,150 ft	1,103 ft	0 ft
Bottom of Plug (MD)	5,334 ft	3,605 ft	1,303 ft	50 ft
Type of Cement or Other Material	Corrosion Resistant	Corrosion Resistant	Portland Cement	Portland Cement
Method of Emplacement	Squeeze	Circulation	Circulation	Circulation

Retainer/CIBP Depth	4,930 ft	3,605 ft	1,303 ft	50 ft
New Plug?	Yes	Yes	Yes	Yes

Figures 6-1 through 6-3 show the final plugging schematics for the three injectors, respectively.



Casing/Tubing Information

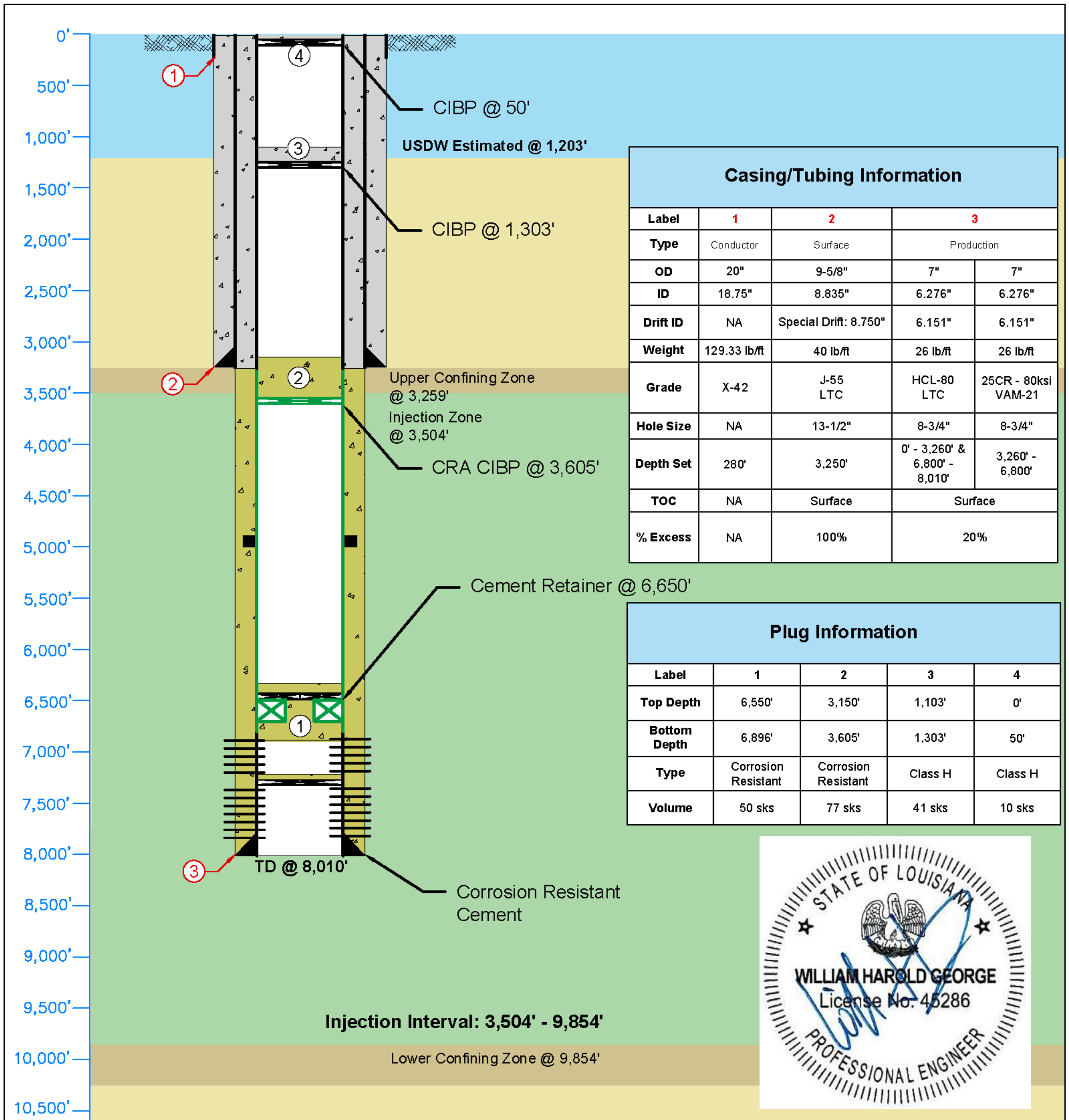
Label	1	2	3	
Type	Conductor	Surface	Production	
OD	20"	9-5/8"	7"	7"
ID	18.75"	8.835"	6.276"	6.276"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"
Depth Set	280'	3,250'	0' - 3,260' & 8,100' - 9,975'	3,260' - 8,100'
TOC	NA	Surface	Surface	
% Excess	NA	100%	20%	

Plug Information

Label	1	2	3	4
Top Depth	7,890'	3,150'	1,103'	0'
Bottom Depth	8,429	3,605'	1,303'	50'
Type	Corrosion Resistant	Corrosion Resistant	Class H	Class H
Volume	90 sks	77 sks	41 sks	10 sks

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 001 P&A	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.226" W, 29° 48' 35.315" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-1 – Final Plugging Schematic for Simoneaux CCS Injector Well No. 001



Casing/Tubing Information

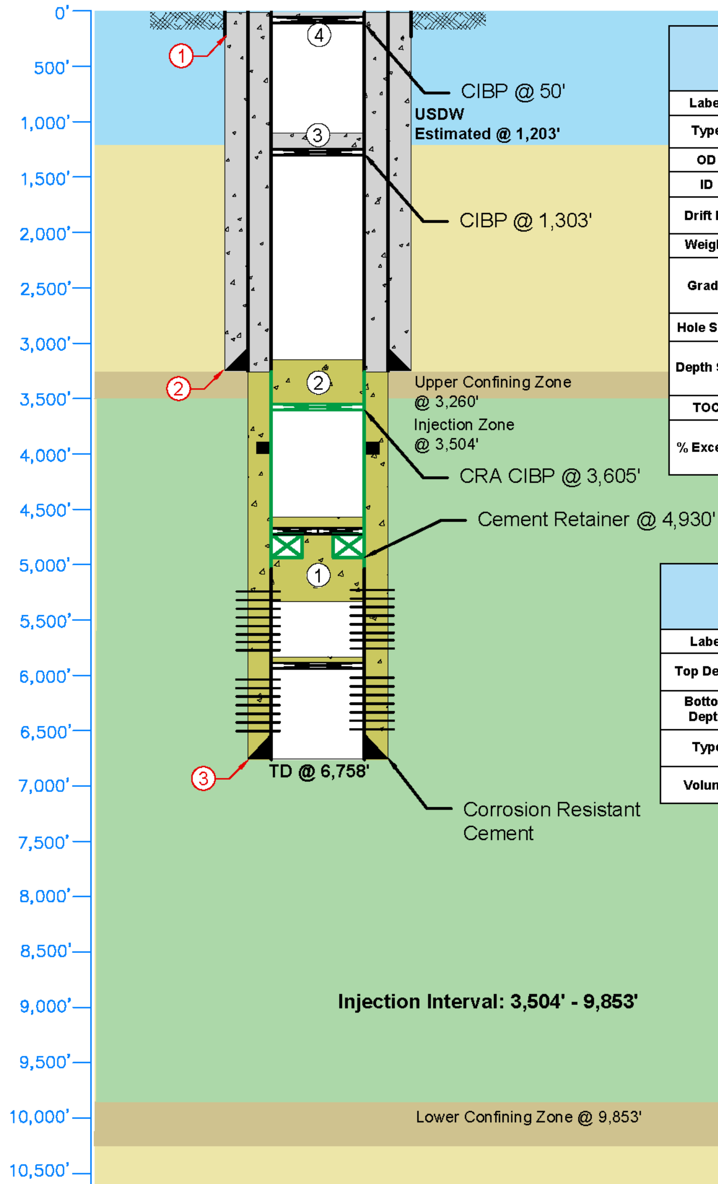
Label	1	2	3	
Type	Conductor	Surface	Production	
OD	20"	9-5/8"	7"	7"
ID	18.75"	8.835"	6.276"	6.276"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"
Depth Set	280'	3,250'	0' - 3,260' & 6,800' - 8,010'	3,260' - 6,800'
TOC	NA	Surface	Surface	
% Excess	NA	100%	20%	

Plug Information

Label	1	2	3	4
Top Depth	6,550'	3,150'	1,103'	0'
Bottom Depth	6,896'	3,605'	1,303'	50'
Type	Corrosion Resistant	Corrosion Resistant	Class H	Class H
Volume	50 sks	77 sks	41 sks	10 sks

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 002 P&A	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 17.510" W, 29° 48' 35.317" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-2 – Final Plugging Schematic for Simoneaux CCS Injector Well No. 002



Casing/Tubing Information

Label	1	2	3	
Type	Conductor	Surface	Production	
OD	20"	9-5/8"	7"	7"
ID	18.75"	8.835"	6.276"	6.276"
Drift ID	NA	Special Drift: 8.750"	6.151"	6.151"
Weight	129.33 lb/ft	40 lb/ft	26 lb/ft	26 lb/ft
Grade	X-42	J-55 LTC	HCL-80 LTC	25CR - 80ksi VAM-21
Hole Size	NA	13-1/2"	8-3/4"	8-3/4"
Depth Set	280'	3,250'	0' - 3,260' & 5,040' - 6,758'	3,260' - 5,040'
TOC	NA	Surface	Surface	
% Excess	NA	100%	20%	

Plug Information

Label	1	2	3	4
Top Depth	4,830'	3,150'	1,103'	0'
Bottom Depth	5,334'	3,605'	1,303'	50'
Type	Corrosion Resistant	Corrosion Resistant	Class H	Class H
Volume	84 sks	77 sks	41 sks	10 sks

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux CCS Injector No. 003 P&A	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 22' 17.793 W, 29º 48' 35.319" N (NAD 27)	**District:**	**Survey:**
	API No: TBD	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-3 – Final Plugging Schematic for Simoneaux CCS Injector Well No. 003

6.3 <u>Monitoring Well Plugging and Abandonment Plans</u>

The following sections detail the P&A of the USDW and AZM monitoring wells associated with the project.

6.3.1 Pre-Plugging Activities for All Wells

Lapis will comply with all reporting and notification provisions, including the following.

1. Notice of Intent to Plug will be communicated to the LDENR by submitting Form UIC-17 with detailed plans (SWO 29-N-1 **§109.D.4**). No actual well-plugging operations will commence until written approval from the Commissioner is received.

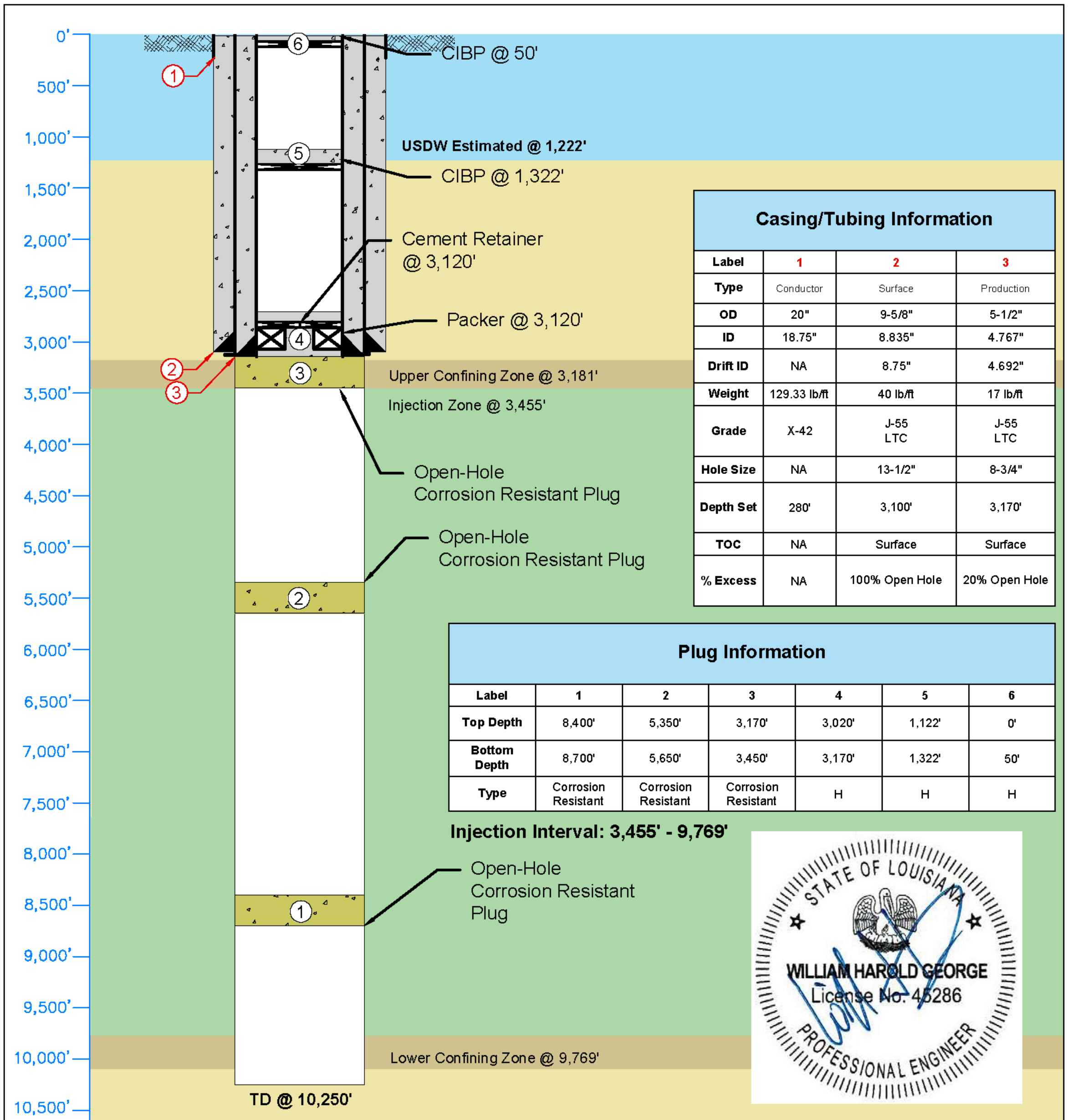
6.3.2 Plugging Procedure for Simoneaux AZM No. 1

Introduction: This procedure covers the permanent P&A of the Simoneaux AZM No. 1 well at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed to abandon the monitoring zone. A series of plugs will then be set to secure the USDW and surface. Finally, the wellhead will be removed and the site left for full reclamation.

Procedure:
1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. N/D the wellhead and N/U the BOPs.
4. Pull and lay down 2 ⅞ in. tubing.
5. Run in hole with the junk basket and gauge ring for 5 ½ in. casing to the packer at 3,120 ft.
6. Wireline set the cement retainer above the packer at 3,120 ft.
7. Trip in hole with the work string, stab into the cement retainer, and establish injection.
8. Squeeze the perforations with 11 cubic ft of cement (16.4 ppg of Class H).
9. Pull out of the retainer and spot 21.5 cubic ft (100 ft) of cement on top of the retainer.
10. Pull above the cement and circulate the work string clean.
11. Pull out of hole with the work string.
12. Test the cement/cement retainer to 500 psi for 30 minutes.
13. Run in hole with the junk basket and gauge ring for 5 ½ in. casing to 1,322 ft.
14. Set the CIBP in 5 ½ in. casing at 1,322 ft.
15. Trip in hole with the work string to 1,322 ft.
16. Mix and pump 43 cubic ft of cement (16.4 ppg of Class H).
17. Pull above the cement and circulate the work string clean.
18. Pull out of hole with the work string.
19. Test the cement/CIBP to 500 psi for 30 minutes.
20. Run in hole with the junk basket and gauge ring for 5 ½ in. casing to 50 ft.
21. Set the CIBP in 5 1/2 in. casing at 50 ft.
22. Trip in hole with the work string to 50 ft.

23. Mix and pump 11 cubic ft of cement (16.4 ppg of Class H).
24. Pull and lay down the remaining work string.
25. Test the cement (per the requirements).
26. Tag the top of the cement.
27. Secure the well. Cut the casing 6 ft below the ground line and weld a plate on top of the casing.
28. RDMO the equipment.

6.3.2.1 <u>Final P&A Wellbore Schematic – Simoneaux AZM No. 1</u>



Casing/Tubing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	20"	9-5/8"	5-1/2"
ID	18.75"	8.835"	4.767"
Drift ID	NA	8.75"	4.692"
Weight	129.33 lb/ft	40 lb/ft	17 lb/ft
Grade	X-42	J-55 LTC	J-55 LTC
Hole Size	NA	13-1/2"	8-3/4"
Depth Set	280'	3,100'	3,170'
TOC	NA	Surface	Surface
% Excess	NA	100% Open Hole	20% Open Hole

Plug Information

Label	1	2	3	4	5	6
Top Depth	8,400'	5,350'	3,170'	3,020'	1,122'	0'
Bottom Depth	8,700'	5,650'	3,450'	3,170'	1,322'	50'
Type	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	H	H	H

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux AZM No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 21' 39.164" W, 29° 49' 03.506" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-4 – Final Plugging Schematic for Simoneaux AZM No. 1

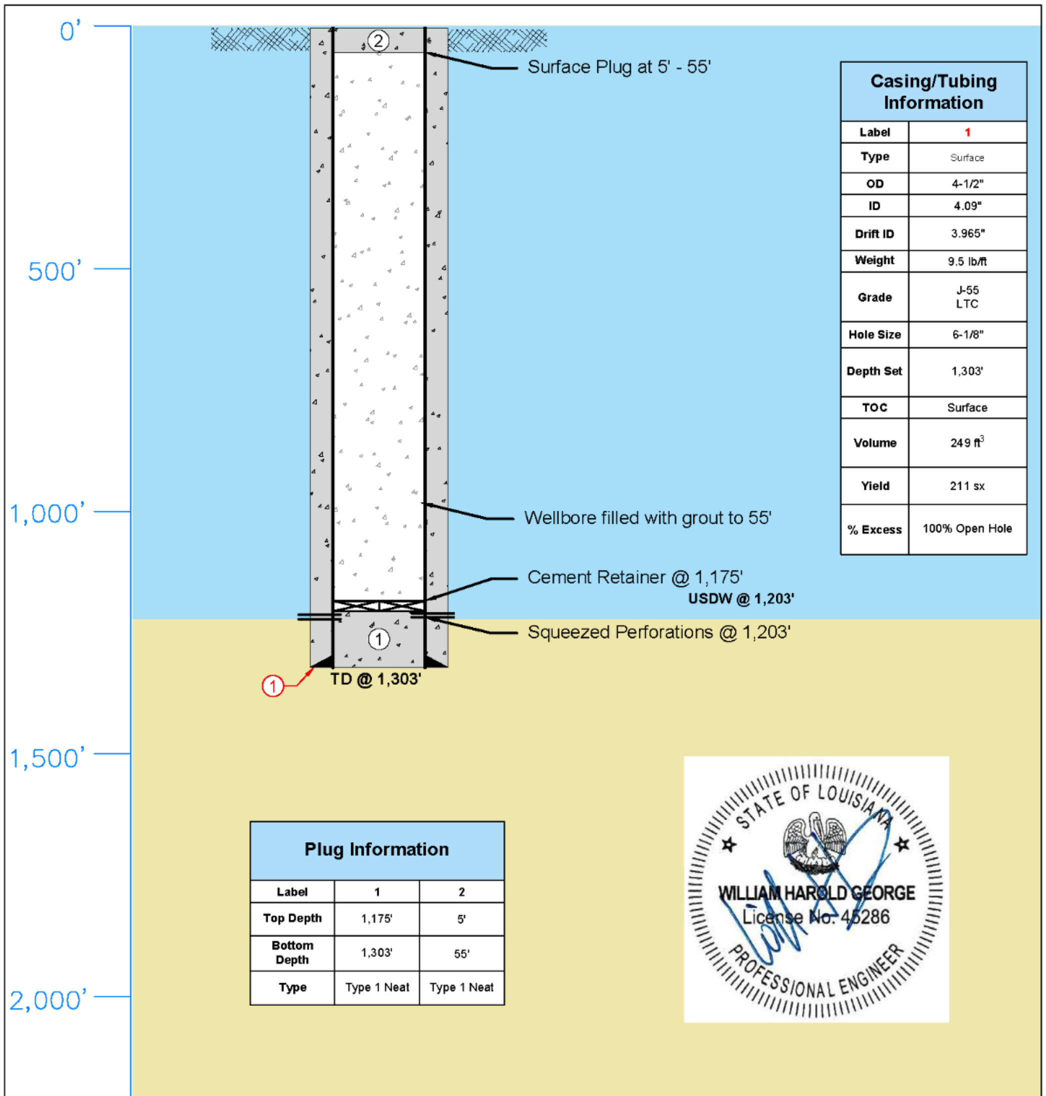
6.3.3 Plugging Procedure for Simoneaux USDW No. 1

Introduction: This procedure covers the permanent P&A of the Simoneaux USDW No. 1 well at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed. The well will be filled with grout, and a cement plug will be set at the surface.

Procedure:

1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. Pull and lay down 2 3/8 in. tubing.
4. Wireline set the cement retainer above the perforations at 1,175 ft.
5. Trip in hole with the work string, stab into the cement retainer, and establish injection.
6. Squeeze the perforations with 20 cubic ft of cement (Type 1).
7. Pull above the cement and circulate the work string clean.
8. Pull out of hole with the work string.
9. Test the cement/cement retainer to 500 psi for 30 minutes.
10. Fill the well with grout from the cement retainer to 55 ft.
11. Trip in hole with the work string to 55 ft.
12. Mix and pump 4.5 cubic ft of cement (Type 1).
13. Pull and lay down the remaining work string.
14. Test the cement (per the requirements).
15. Tag the top of the cement.
16. Secure the well. Cut the casing 5 ft below the ground line and weld a plate on top of the casing.
17. RDMO the equipment.

6.3.3.1 Final P&A Wellbore Schematic – Simoneaux USDW No. 1



Casing/Tubing Information

Label	1
Type	Surface
OD	4-1/2"
ID	4.09"
Drift ID	3.965"
Weight	9.5 lb/ft
Grade	J-55 LTC
Hole Size	6-1/8"
Depth Set	1,303'
TOC	Surface
Volume	249 ft³
Yield	211 sx
% Excess	100% Open Hole

Plug Information

Label	1	2
Top Depth	1,175'	5'
Bottom Depth	1,303'	55'
Type	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux USDW No. 001	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90° 22' 15.764" W, 29° 48' 33.819" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-5 – Final Plugging Schematic for Simoneaux USDW No. 1

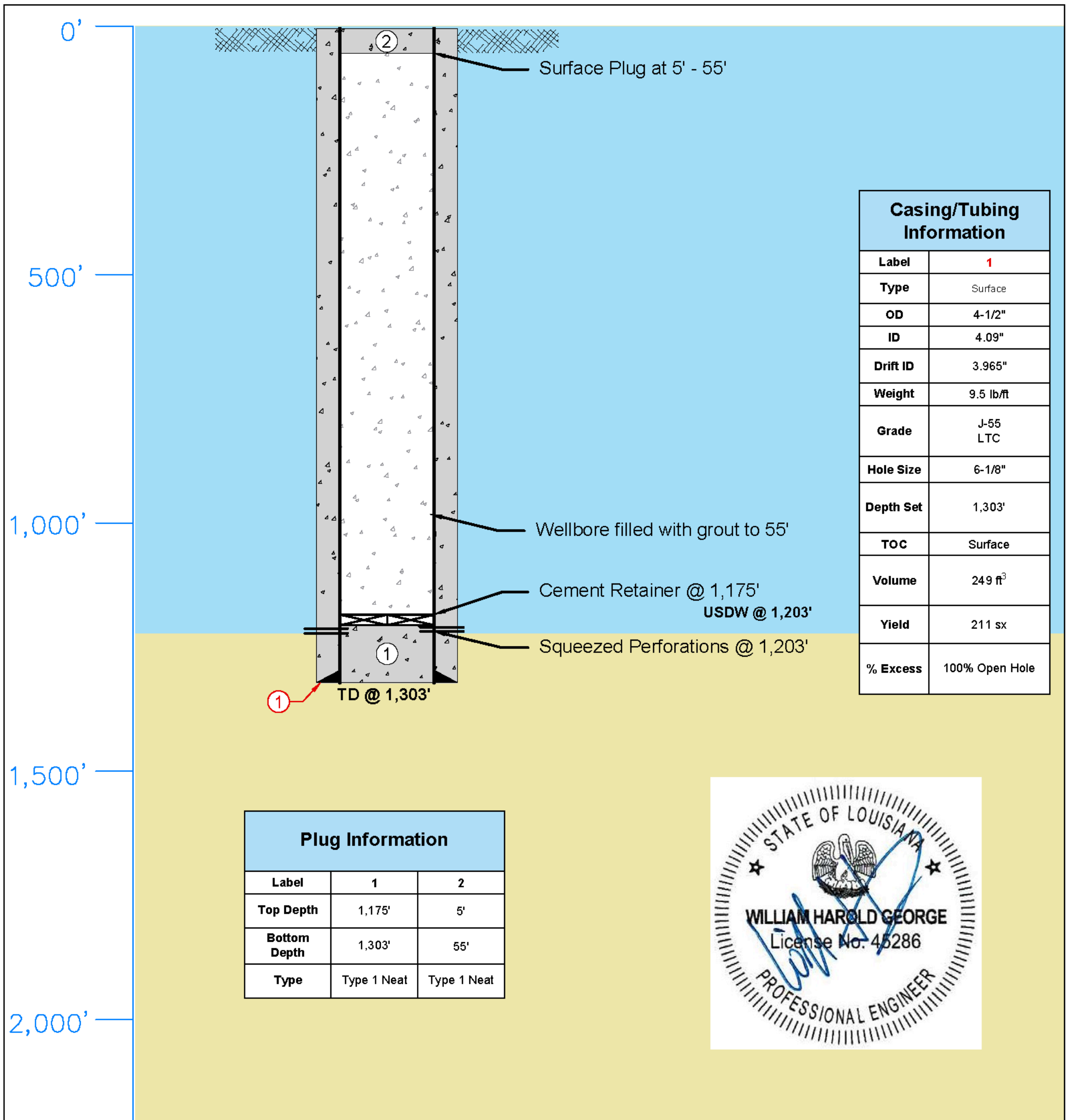
6.3.4 Plugging Procedure for Simoneaux USDW No. 2

Introduction: This procedure covers the permanent P&A of the Simoneaux USDW No. 2 well at the end of the life of the Libra project. The tubing will be pulled, and the perforations will be squeezed. The well will be filled with grout and a cement plug will be set at surface.

Procedure:

1. Mobilize the crew and equipment to the location.
2. Spot and rig up the equipment.
3. Pull and lay down 2 3/8 in. tubing.
4. Wireline set the cement retainer above the perforations at 1,175 ft.
5. Trip in hole with the work string, stab into the cement retainer, and establish injection.
6. Squeeze the perforations with 20 cubic ft of cement (Type 1).
7. Pull above the cement and circulate the work string clean.
8. Pull out of hole with the work string.
9. Test the cement/cement retainer to 500 psi for 30 minutes.
10. Fill the well with grout from the cement retainer to 55 ft.
11. Trip in hole with the work string to 55 ft.
12. Mix and pump 4.5 cubic ft of cement (Type 1).
13. Pull and lay down the remaining work string.
14. Test the cement (per the requirements).
15. Tag the top of the cement.
16. Secure the well. Cut the casing 5 ft below the ground line and weld a plate on top of the casing.
17. RDMO the equipment.

6.3.4.1 Final P&A Wellbore Schematic – Simoneaux USDW No. 2



Casing/Tubing Information

Label	1
Type	Surface
OD	4-1/2"
ID	4.09"
Drift ID	3.965"
Weight	9.5 lb/ft
Grade	J-55 LTC
Hole Size	6-1/8"
Depth Set	1,303'
TOC	Surface
Volume	249 ft^3
Yield	211 sx
% Excess	100% Open Hole

Plug Information

Label	1	2
Top Depth	1,175'	5'
Bottom Depth	1,303'	55'
Type	Type 1 Neat	Type 1 Neat

LONQUIST SEQUESTRATION LLC	Lapis Energy (LA Development), LP	Simoneaux USDW No. 002	
	Country: USA	**State/Province:** Louisiana	**County/Parish:** St. Charles
	Location: 90º 21' 40.359" W, 29º 49' 04.471" N (NAD 27)	**District:**	**Survey:**
	API No:	**Field:**	**Well Type/Status:**
Louisiana License EF-7423	**Serial No:** TBD	**Project No:** LS169	**Date:** 11/18/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Connor Lofton	**Reviewed:** Andrew Ellis	**Approved:** William H. George, P.E.
	Rev No: 1	**Notes:**	

Figure 6-6 – Final Plugging Schematic for Simoneaux USDW No. 2

Appendix H – Well Plugging Schematics and Procedures:

- Appendix H-1 Simoneaux CCS Injector Well No. 001 Final P&A Schematic
- Appendix H-2 Simoneaux CCS Injector Well No. 002 Final P&A Schematic
- Appendix H-3 Simoneaux CCS Injector Well No. 003 Final P&A Schematic
- Appendix H-4 Simoneaux AZM No. 01 Final P&A Schematic
- Appendix H-5 Simoneaux CCS Injector Well No. 001 Detailed Plugging Procedure
- Appendix H-6 Simoneaux CCS Injector Well No. 002 Detailed Plugging Procedure
- Appendix H-7 Simoneaux CCS Injector Well No. 003 Detailed Plugging Procedure
- Appendix H-8 Simoneaux AZM No. 01 Detailed Plugging Procedure
- Appendix H-9 Simoneaux USDW No. 001 P&A Schematic
- Appendix H-10 Simoneaux USDW No. 002 P&A Schematic

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

TABLE OF CONTENTS

Figures

Tables

7.1 Introduction

The Post-Injection Site Care (PISC) and Site Closure Plan for the Lapis Energy (LA Development), LP (Lapis) project - Libra CO_2 Storage Solutions (Libra) Project—for the Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003—was prepared to meet the requirements of Statewide Order (SWO) 29-N-6 **§3633.A.1** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.93(a)**]. This plan describes the various activities that will occur once injection has ceased and during the site closure. The Site Closure Plan will be implemented once Lapis demonstrates that no additional monitoring is needed to ensure that this project poses no further endangerment to Underground Sources of Drinking Water (USDWs).

7.2 Pre- and Post-Injection Pressure Differentials

The following table (Table 7-1) shows the expected pressure differential between pre-injection and predicted post-injection pressures in the injection zone, as determined by the plume model described in *Section 2 – Plume Model*. As discussed there and in *Section 4 – Engineering Design and Operating Strategy*, all three proposed injection wells will inject into sequentially shallower intervals over the life of the Libra Project, resulting in separate pressure profiles for each interval.

The highest pressure differential for Simoneaux CCS Injector Well No. 001 occurs in Year 11, which is part of Completion Stage 2, and is predicted to reach 657 pounds per square inch (psi). The highest pressure differential for Simoneaux CCS Injector Well No. 002 occurs in Year 12, which is also part of Completion Stage 2 and predicted to reach 640 psi. The highest pressure differential for Simoneaux CCS Injector Well No. 003 occurs in Year 13, which is part of Completion Stage 2 as well and predicted to reach 267 psi. Once injection ceases in each stage, the pressure drops to near-reservoir pressures. Table 7-1 shows the maximum pressure differential predicted at each wellbore in each year modeled. Modeled bottomhole (BHP) data is available for Years 1-20. For Years 21–70, the data originates from the average cell reservoir pressure at the same depth of the BHP.

Table 7-1 – Maximum Pressure Differential by Year for the Simoneaux CCS Injectors

Year	Maximum Pressure Differential (psi) Injector Well No. 001	Maximum Pressure Differential (psi) Injector Well No. 002	Maximum Pressure Differential (psi) Injector Well No. 003
1	532	-	-
2	487	489	-
3	462	463	261
4	442	444	209
5	425	428	184
6	411	415	168
7	400	405	156
8	388	397	146
9	378	390	138
10	369	385	133
11	657	381	128
12	595	640	123
13	562	549	267
14	541	505	250
15	523	477	241
16	510	457	236
17	499	442	230
18	490	429	226
19	483	418	222
20	475	410	219
21	78.8	0	35.2
25	22.0	0	3.0
30	19.0	0	1.9
35	17.8	0	1.9
40	16.5	0	1.4
50	14.9	0	0.7
60	13.2	0	0.8
70	11.6	0	1.4

Figures 7-1 through 7-3 present graphical representations of the data in Table 7-1, showing the differential pressure over the life of the three injection wells. The black line represents the buildup from in situ reservoir pressure; this is the pressure change due to injection. The light blue line represents the maximum pressure gradient experienced in the wellbores. The red dashed line shows the maximum bottomhole pressure constraint as a gradient, indicating that the model does not surpass this maximum pressure.

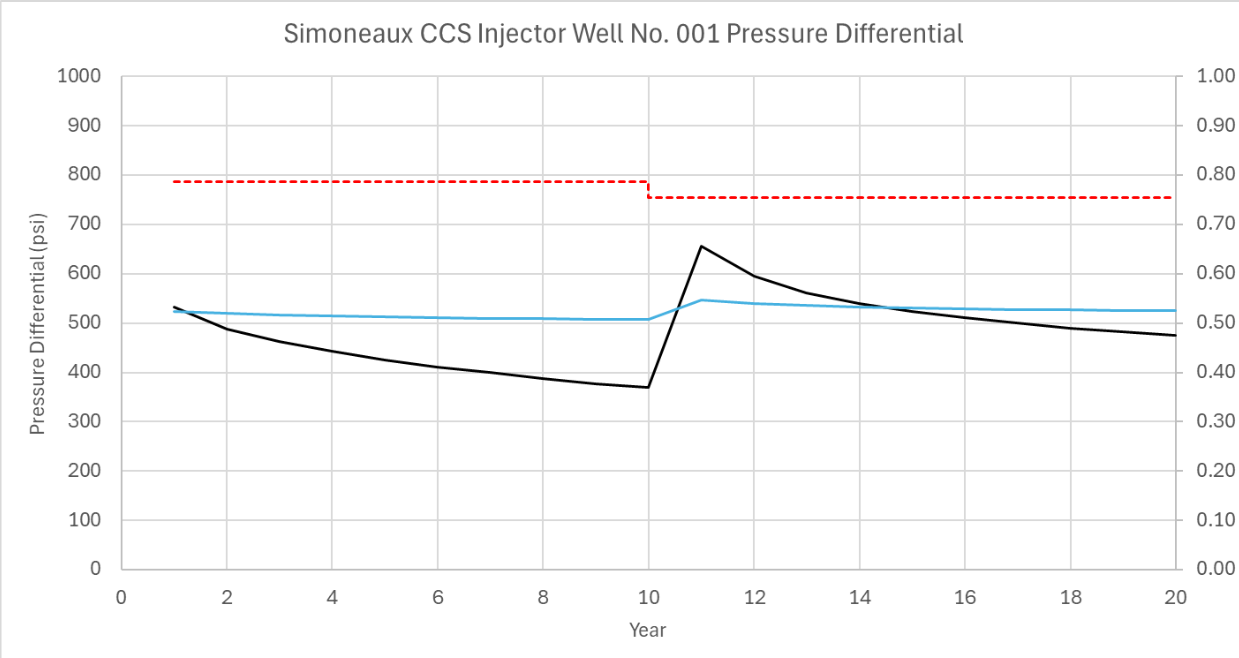


Figure 7-1 – Maximum Pressure Differential Over Time for Simoneaux CCS Injector Well No. 001

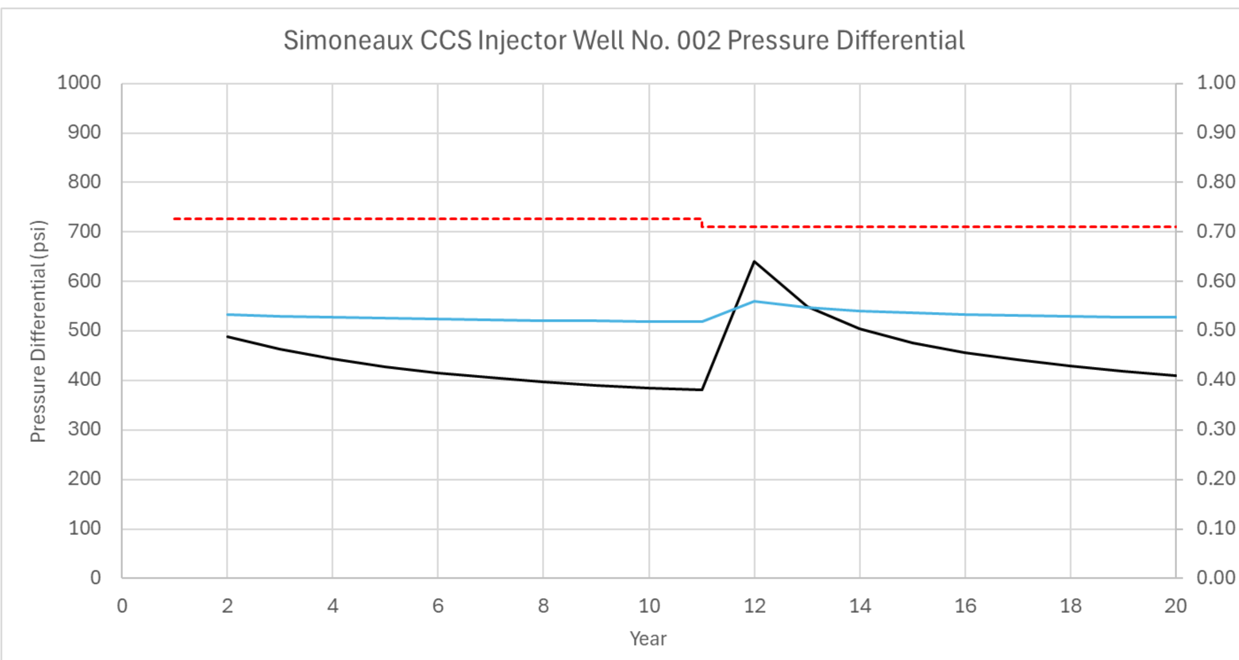


Figure 7-2 – Maximum Pressure Differential Over Time for Simoneaux CCS Injector Well No. 002

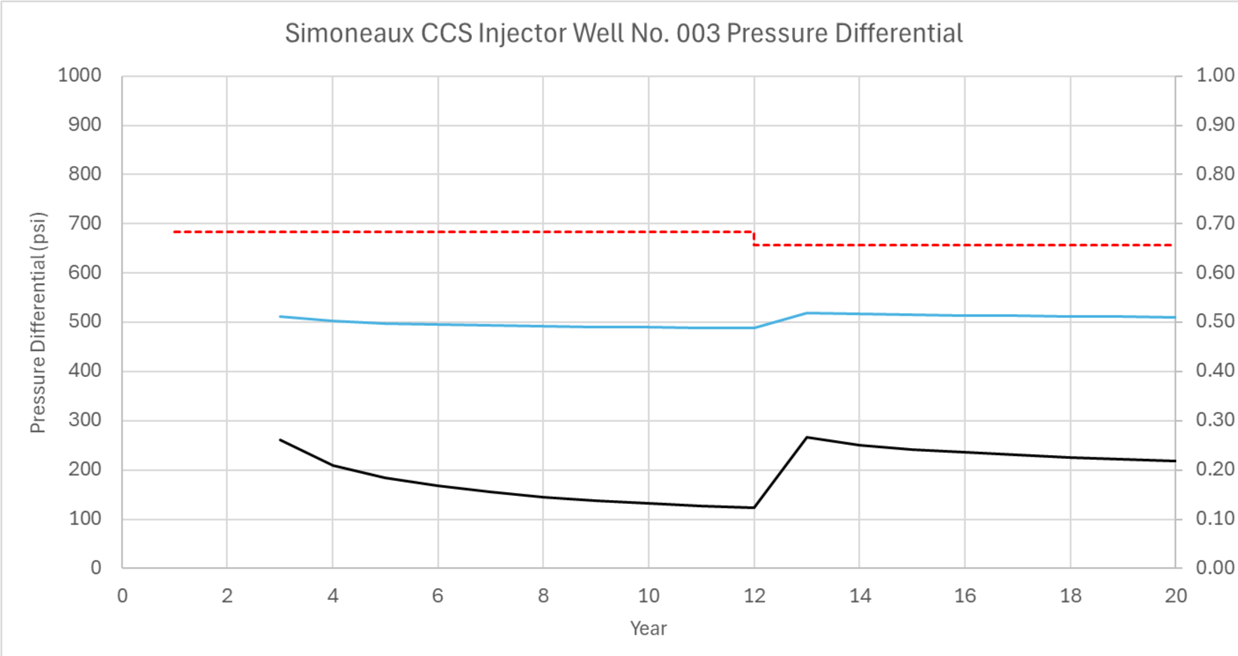


Figure 7-3 – Maximum Pressure Differential Over Time for Simoneaux CCS Injector Well No. 003

7.3 CO_2 Plume Position and Pressure Front at End of Closure

The area of review (AOR) consists of both the CO_2 plume and critical pressure maximum extent. Figure 7-4 shows the AOR and its subcomponents. The CO_2 plume is indicated by the black outlined area, based on the maximum extent of all the differing plume layers in the model, extracted at 50 years post-injection. The pink outlined area represents the critical pressure front. The CO_2 plume area and critical pressure front AOR consider Simoneaux CCS Injector Wells No. 001, No. 002, and No. 003.

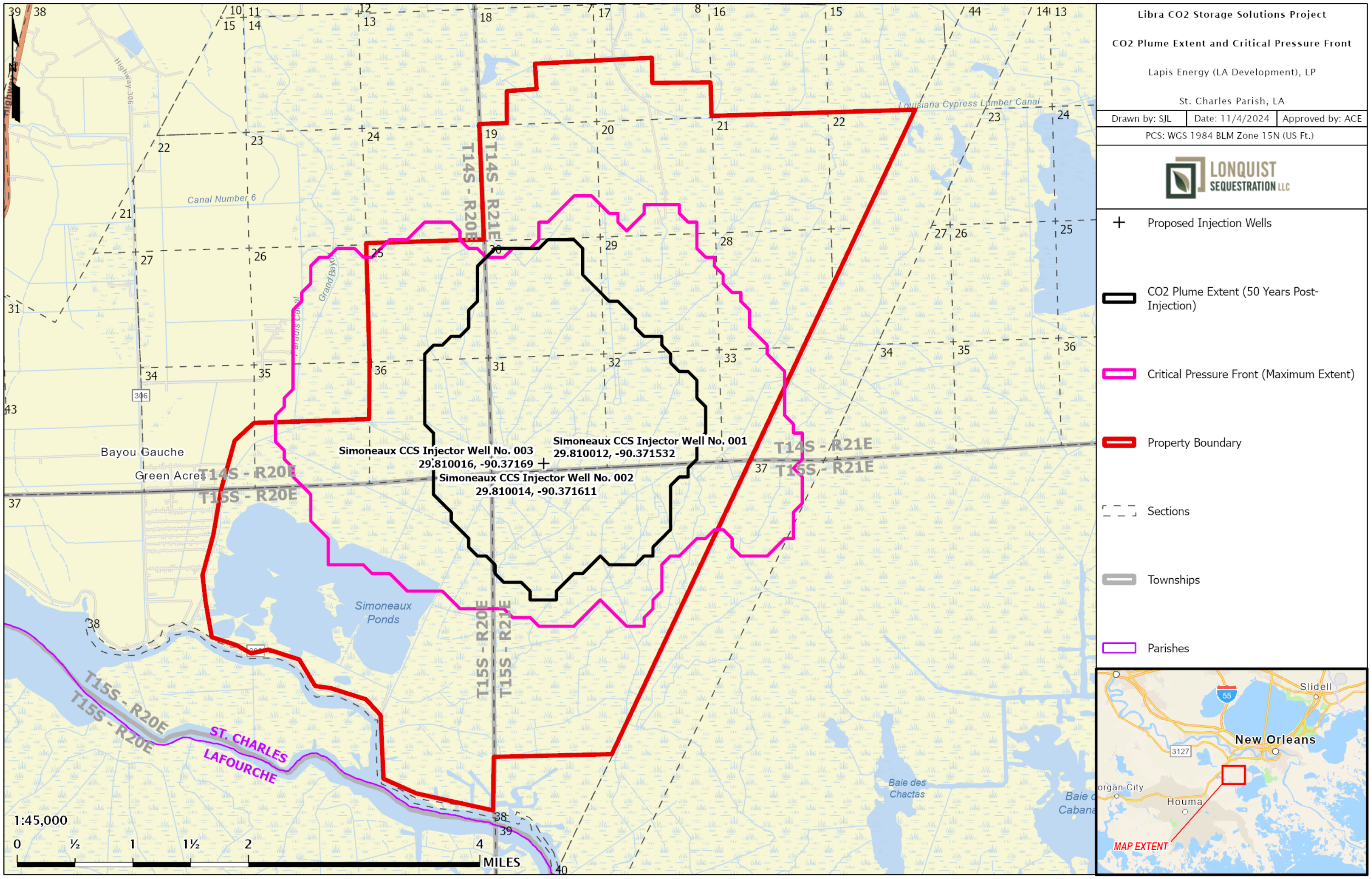


Figure 7-4 – CO_2 Plume and Pressure Front

Plume growth stability is one of the main metrics that will prove non-endangerment of the USDW. The graph in Figure 7-5 shows the composite plume growth of all three injectors post-injection as an annualized percentage change in the plume area. Monthly time steps are plotted for the first 5 years—with yearly time steps for Years 5 to 70 and every 5 years after that. Smaller time steps were taken for the initial period to adequately capture the initial decline in plume growth. A power trend was fitted through the points (dark blue dotted line). This shows that the plume stabilizes around 40–50 years post-injection at a negligible residual 0.5% plume growth. A black manually fitted trend line was also included, showing a similar behavior. Based on these simulation results, Lapis proposes a 50-year PISC time frame. During injection—as part of the regular 5-year AOR reevaluations—the PISC time frame will also be reevaluated based on actual monitoring data and adjusted up or down accordingly, following approval from the Louisiana Department of Energy and Natural Resources (LDENR).

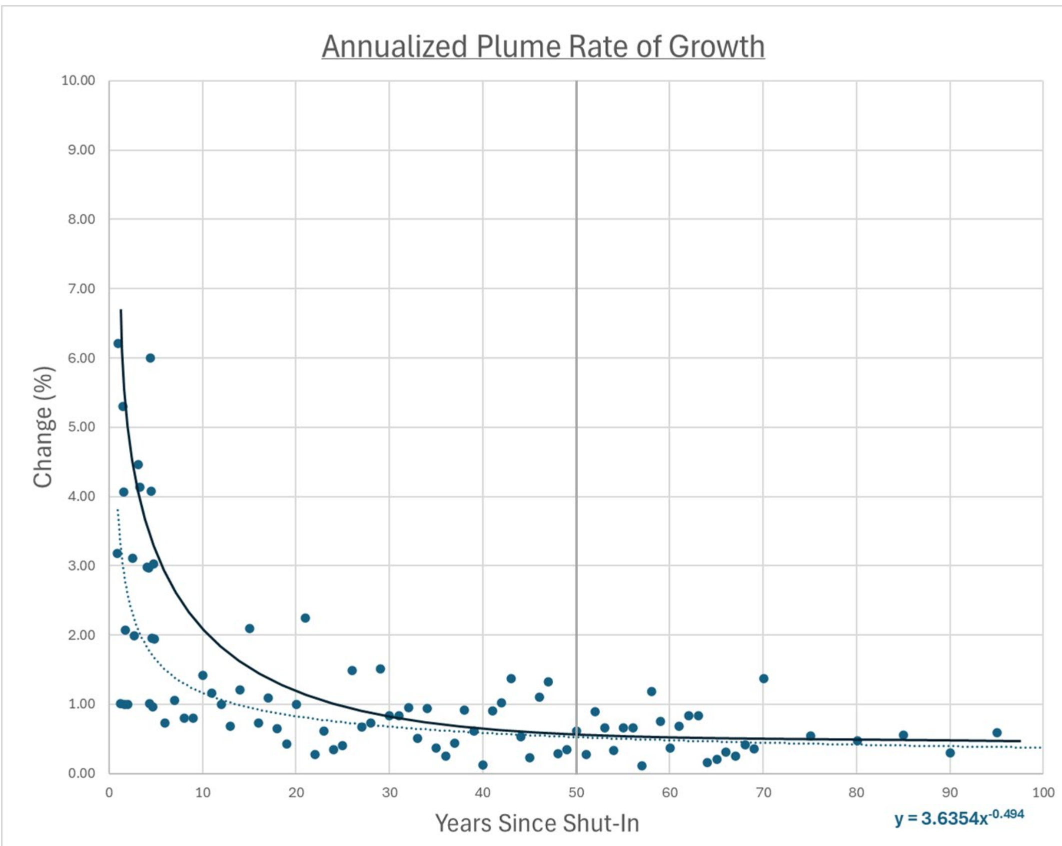


Figure 7-5 – Annualized Composite Areal Plume Rate of Growth During the PISC

7.4 Post-Injection Monitoring Plan

Lapis will continue to monitor the site for 50 years or until it is demonstrated that the Libra Project no longer poses a potential endangerment to the USDW, as described in *Section 7.6*. The reservoir model will continue to be updated using monitoring data, throughout the Libra Project.

Upon cessation of injection, an amended PISC—if the updated model warrants it—will be submitted to the Commissioner of Conservation (Commissioner).

7.5 Post-Injection Monitoring Activities

During the monitoring period, the testing and monitoring activities, as described in *Section 5 – Testing and Monitoring Plan,* will be performed and reported at the frequency shown in Table 7-2. The post-injection monitoring results will be submitted to the Commissioner and to the EPA.

Table 7-2 – Post-Injection Monitoring and Reporting Frequency

Testing/Monitoring Activity	Frequency	Reporting Schedule
USDW monitoring well fluid sampling and analysis	At least once every 5 years	As Required
Injection-well wellhead pressure monitoring (tubing and annulus)	Continuously	As Required
Injection well pressure/temperature (P/T) monitoring	Continuously, using P/T gauges in each injection well	As Required
Indirect plume monitoring (sparse permanent seismic monitoring system)	At least once every 10 years	As Required
Direct plume calculations based on P/T data	Annually	As Required

All testing and monitoring activities listed will be performed and analyzed as discussed in *Section 5*, including quality assurance/quality control (QA/QC) measures.

7.6 Demonstration of Non-Endangerment of USDW

The primary mechanism through which the USDWs are protected is the upper confining zone (UCZ), which is characterized as a single confining shale. The monitoring data that will be collected after injection ceases verifies that the UCZ is functioning as expected and that the USDW is not endangered.

The monitoring data will also be used to calibrate the simulation model and further enhance its ability to accurately predict the movement of CO_2. These calibrated simulation-model predictions are used to identify any UCZ-penetrating features with which the CO_2 plume may interact prior to final stabilization. Examples of these features of concern are legacy wellbores and fault planes. Any legacy wellbore with which the CO_2 plume is modeled to interact will be assessed, to determine if it is adequately abandoned. This effort ensures that (1) legacy wellbores do not compromise the integrity of the UCZ, and (2) the USDW is not endangered. The calibrated simulation-model predictions are also used to verify that CO_2 does not reach fault planes cutting through the UCZ.

Prior to the approval of the site-closure authorization, Lapis will provide documentation that the USDW is not at risk of future endangerment from the CO_2 plume. While the PISC duration is 50 years, it may be possible to demonstrate USDW non-endangerment earlier. For example, after 10 years of post-injection monitoring, multiple sets of time-lapse seismic survey images, combined with other monitoring measurements, will be available to demonstrate the containment of the plume. Lapis will submit a report to the Commissioner supporting non-endangerment of the USDW, including site-specific conditions, an updated plume model, the predicted pressure decline within the injection zone, and any updates to the underlying geological assumptions used in the original model.

7.7 Site Closure Plan

The following activities will be performed to meet the site closure requirements: plugging of all wells, site closure, and submittal of final site-closure reports.

7.7.1 Pre-Closure

Notice of Intent to Close the site will be submitted to the Commissioner at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

7.7.2 Plugging Activities

The proposed injection, above-zone monitoring (AZM), and USDW monitoring wells will be plugged as discussed in *Section 6 – Injection Well Plugging Plan*. The plugging and abandonment procedures for the injectors include measures to prevent CO_2 or formation fluids in the injection interval from migrating to the USDW. Prior to plugging the injection and monitoring wells, the mechanical integrity of those wells will be verified. Plugging schematics and procedures are provided in *Appendix H*.

7.7.3 Site Restoration

Once the injection and monitoring wells are plugged and capped below grade, all surface equipment will be decommissioned and removed. The site will be restored according to the agreement with the surface owner.

7.7.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the Commissioner and the EPA, and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats, which will indicate the location of the injection wells relative to permanently surveyed benchmarks
- Documentation of well-plugging report to the LDENR
- Documentation of notification and information to appropriate authorities that have authority over drilling activities, to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones
- Records of the nature, composition, and volume of the CO_2 stream over the injection period

A record of notation in the facility property deed will be added to provide, in perpetuity, any potential purchaser of the property the following information:

- A complete legal description of the affected property
- The fact that the land was used to sequester CO_2
- The name of the state agency (LDENR) with which the survey plat was filed, and the address of the EPA Regional Office to which it was submitted
- The total volume of fluid injected, the injection zones into which it was injected, and the period over which the injection occurred

Lapis will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, Lapis will deliver all records to the Commissioner for retention at a location designated by the Commissioner for that purpose.

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

TABLE OF CONTENTS

Figures

None

Tables

8.1 Introduction

This Emergency and Remedial Response Plan (ERRP) for the Lapis Energy (LA Development), LP (Lapis) Libra CO_2 Storage Solutions Project (Libra) was prepared to meet the requirements of Statewide Order (SWO) 29-N-6, **§623** [Title 40, US Code of Federal Regulations (40 CFR) **§146.94**]. The plan describes potential adverse events that could occur in the development, operation, and post-closure phases of the project and the actions to be taken in the event of such an emergency. This plan will be reviewed and updated annually. Any change in key personnel will also cause the plan to be updated.

8.1.1 Facility Information

Project Name: Libra CO_2 Storage Solutions Project

Project -Contact: Brandon Anderson, Libra Project Manager
Lapis Energy (LA Development), LP
5420 LBJ Fwy, Bldg. 2
Suite 1330
Dallas, Texas 75240
469-629-1766 / permitting@lapisenergy.com

Well Locations: St. Charles Parish

Simoneaux CCS Injector Well No. 001
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.315" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.226" W

Simoneaux CCS Injector Well No. 002
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.317" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.510" W

Simoneaux CCS Injector Well No. 003
Latitude Coordinate (GCS, NAD 27): 29° 48' 35.319" N
Longitude Coordinate (GCS, NAD 27): 90° 22' 17.793" W

*CCS – carbon capture and sequestration
Geologic coordinate system (GCS) –
NAD 27 – North American Datum of 1927

8.2 Resources/Infrastructure in AOR

The proposed injection facilities are located approximately 2 miles (mi) north of the town of

Bayou Gauche, Louisiana, and approximately 20 mi southwest of New Orleans, Louisiana. The eastern side of the Simoneaux property borders the Salvador Wildlife Management property, and the western and northern boundaries border multiple residential areas, the closest being approximately 2 mi.

Resources in the vicinity of the proposed injection facilities that may be affected as a result of an emergency event include the following, as presented in *Appendix G-2*:

- Nearest freshwater well – 3.0 mi
- Nearest drinking water well – 5.0 mi
- Simoneaux Ponds – 1.4 mi
- Bayou des Allemands – 2.6 mi
- Grand Bayou Canal – 2.2 mi

These freshwater resources, which have been identified within or proximal to the Libra project site, have been determined to be at least 2,000 feet (ft) above the proposed subsurface-injection reservoir targets. Although there is little likelihood that facility operations at the project site would negatively impact any of these freshwater resources at any point in time during the life of those operations, the protection of these important resources is still considered of paramount importance and will be discussed throughout this ERRP.

Infrastructure in the vicinity of the proposed injection facilities that may be affected as a result of an emergency includes the following, as detailed in *Appendix G-2*:

- <u>Oil/Gas Facilities</u>
    - Bridgeline Holdings Pipeline LP
    - LLOX Production Facility
- <u>Electrical Infrastructure</u>
    - *High voltage transmission lines operated by Entergy*

The proposed injection wells and the plume extent are located on and below a body of brackish water. The wells' location and the plume extent are shown in *Appendix C-5.*

The lowermost Underground Source of Drinking Water (USDW) in the area of review (AOR)—well SN 81236—is estimated to be found at approximately 1,222 feet (ft) from the Kelly bushing (1,203 (ft) from ground level) at the project site from a pick in the nearest offset well, the Waterford Oil Co. No. 001 (SN 81236)., as discussed in *Section 1 – Site Characterization*.

8.3 <u>Degrees of Risk</u>

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 8-1.

Table 8-1 – Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated immediately.
Serious Emergency	Event poses potential serious (or significant) near-term risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Monitoring and alarm systems will provide notifications of a potential leak of CO_2 or formation fluids out of regulatory zones, from the injection wells, monitoring wells, or surface facilities (i.e., pipelines, storage systems, etc.). Alarms will also be set to monitor injection parameters, mechanical well integrity, and the injection system integrity. If data shows that there is leakage from the reservoir system or a mechanical well failure, the operator will follow the initial steps to assess the emergency risks as defined above.

Secondly, the operator/facility will follow these identified actions:

- The project will activate the emergency and remediation response protocol consistent with this ERRP and the circumstances of the event.
- The Commissioner of Conservation (Commissioner) will be notified within 24 hours of the event being discovered.

The Commissioner may allow the operator to resume injection prior to remediation if the storage operator demonstrates that the injection operation will not endanger the USDW.

8.4 <u>Infrastructure/Resource – Specific Events and Response Plans</u>

The following scenarios represent a high-level concept of potentially significant adverse events, likelihood of occurring, methods of prevention and detection, and likely remedial responses.

8.4.1 Event Description – Well Blowout

Likelihood: Not Likely

A well blowout could occur during wellbore drilling if unexpected changes in reservoir pressures cause a sudden release of hydrocarbons and/or pressure from the subsurface formations.

Prevention and Detection:

- Maintain appropriate mud weights as required based on offset well data.

- Monitor rate of drilling fluid returns vs. rates pumped, penetration rates, pump pressures, etc.

Severity and Risk:

- Degree of risk: Major Emergency (as defined in Table 8-1)
- The risk of this type of event ever occurring is considered very low and unlikely.
- The severity of this type of event is relatively low if the cause of the event is immediately and properly addressed. However, if not immediately mitigated, a well control event can become a highly severe and dangerous problem if it leads to a loss of control and presents an impact to human health and infrastructure.

Potential Response Actions:

- Cease drilling operations.
- Close the blowout preventer; insert rams into the well.
- Read and record stabilized shut-in pressures. Calculate kill weight mud fluid weight.
- Secure the rig floor and surrounding rig area.
- Initiate well control procedures.
- Kill the well by circulating kill weight mud around. Shut down pumps and monitor for flow.

Response Personnel: On-site certified well control rig supervisor and third-party certified well control Lapis supervisors

Equipment: Drilling rig, mud logging equipment, well control equipment, drilling fluid materials to adequately increase mud weight

8.4.2 Event Description – CO_2 Migration: Pore Space / Mineral Rights Infringement (Trespass)

Likelihood: Not Likely

This event could occur if the plume expands beyond what the reservoir model predicts and migrates off of controlled acreage and into neighboring pore space not controlled by the operator. This could also occur if the plume expansion causes the plume to migrate into adjacent mineral resources that may affect economic production from that area.

Prevention and Detection:

- The CO_2 plume will be monitored as described in *Section 5 – Testing and Monitoring Plan*. If the CO_2 plume appears to encroach on the property boundary faster than expected, adjust the injection strategy (e.g., reduce the rate in the problematic zone or recomplete in a new zone).
- Obtain control of pore space through outright ownership or lease agreements.

Severity and Risk:

- Degree of risk: Minor Emergency (as defined in Table 8-1)
- The risk of this type of event occurring is considered unlikely.
- The severity of this type of event is low not only because the plume migration will be constantly monitored as detailed in *Section 5 – Testing and Monitoring Plan*, but also because the trespass poses no immediate risk to human health.

Potential Response Actions:

- Lower the injection rates or stop the injection and notify the Commissioner within 24 hours.
- Restart the injection, if possible, at a reduced rate.
- Possibly recomplete into a new, shallower injection interval.
- If trespass is detected or identified to be likely:
    - Begin negotiations with a neighboring landowner to acquire rights to store within adjacent pore spaces.
- If hydrocarbon resource infringements are detected or identified to be likely:
    - Begin negotiations with mineral owners to determine the impact of the infringement.

Response Personnel:

- The responsible parties will be the site personnel involved with the well operations.
- Landman, if required

Equipment:

- Not applicable

8.4.3 Event Description – Water Quality Contamination with Drilling Fluid

Likelihood: Not Likely

This event could happen during the drilling of the wells and the operations of the injection facility. Drilling fluid may contaminate the potable water aquifer.

Prevention and Detection:

- Losses will be monitored during all phases of the drilling of the injection and monitoring wells.
- Best practice drilling methods and procedures will be employed to limit a potential leakage event.
- Monitoring parameters such as tank levels, flow lines, and flow pressures will lead to a first detection response.
- The wells are designed to prevent the likelihood of this occurring.

Severity and Risk:

- Degree of risk: Minor Emergency (Table 8-1)

- The potential risk of contamination of a USDW because of the drilling and construction of the wells is considered low.
- If there is a documented (localized) invasion/contamination of the USDW with the nontoxic drilling fluid, the impact would be considered a minor emergency event; therefore, a release would not constitute an immediate risk to human health, resources, or infrastructure.

Potential Response Actions:

- Cease all drilling operations and assess fluid levels in the wellbore.
- Evaluate the drilling parameters, tank levels, and flow lines.
- Determine the amount of potential fluid losses and at what specific depth.
- Treat the mud with lost circulation materials and adjust the mud weight to allow for continuation of drilling operations.
- Check for leaks in the casing and at the casing shoe. *If* detected, then squeeze/patch the identified defect.
- Verify the integrity of the cement with additional cement band log run(s), if required.
- If a leak is detected in the surface casing, it will be squeezed with additional cement or patched, and the post-repair cement integrity will then be reaffirmed prior to resuming drilling operations.

Drilling operations will only resume once the post-repair testing of the surface casing and its cement job confirms its integrity. The casing shoe of the surface casing will also be pressure-tested to verify its integrity prior to proceeding to the next phase of drilling.

Response Personnel:

- On-site drilling personnel and supervisors

Equipment:

- The tank levels and pressure and flow meters will be checked and recalibrated if required.
- Logging equipment

8.4.4 Event Description – Water Quality Contamination with Injectate

Likelihood: Not Likely

This event could happen during operations of the injection facility. This could occur if the plume reaches faults or fractures that allow brine or CO_2 migration into another zone, including the USDW. Failure of the confining zone could also cause migration and contaminate the USDW.

Prevention and Detection:

- The CO_2 plume will be monitored in real-time as described in *Section 5 – Testing and Monitoring Plan*.
- The well is designed to prevent the likelihood of this occurring.

- Mechanical barriers to CO_2 leakage and monitoring controls will be put in place to reduce the potential risk of vertical CO_2 leakage to the USDW.

Severity and Risk:

- Degree of risk: Minor to Serious Emergency (Table 8-1)
- The risk of brine or CO_2 migration due to faults, fractures, or failure of the confining zone is low.
- Should an unlikely leakage event occur—depending on the amount of CO_2 or brine leakage and the time that might have elapsed between the onset and subsequent discovery of such a leak—the severity of such an event could range from minor to serious.

Potential Response Actions:

- Lower the injection rates or stop the injection and notify the Commissioner within 24 hours.
- Use installed permanent seismic monitoring to assess the location and degree of CO_2 movement, as described in *Section 5 – Testing and Monitoring Plan*.
- Identify the point of potential leakage.
- Resume the injection, if possible, at a reduced rate.
- If groundwater/USDW is affected:
    - Pump CO_2/brine-contaminated groundwater to the surface and aerate it to remove injectate.
    - Apply methods to remove trace elements.
    - Provide an alternative water supply if groundwater-based public water supplies are contaminated.
- If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete uphole into the next planned injection interval.

Response Personnel:

- The responsible parties will be the site personnel involved with the well operations.
- Environmental, Health, and Safety manager
- Drilling manager
- Additionally, technical consultants, remediation experts, and local health authority will be engaged.

Equipment:

- The type of equipment involved in remediation would depend on the type and severity of the leak. Such equipment would likely range from the use of workover rigs, additional CO_2-resistant cement, and other remedial equipment, to the potential installation of downhole remediation equipment (pumps, filters, etc.), as deemed necessary.

8.4.5 Event Description – Loss of Mechanical Integrity

Likelihood: Not Likely

This event could occur due to either a casing, tubing, or packer failure, or cement degradation from corrosion/erosion due to long-term CO_2 exposure.

Prevention and Detection:

- Proper wellbore design, including proper cement and metallurgy of the casing and tubing, will be implemented in the construction phase.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- Automatic alarm and automatic shutoff systems will be installed to trigger digital notification and audible alarms if an injection well loses integrity during operation.

Severity and Risk:

- Degree of risk: Minor Emergency (Table 8-1)
- The potential risk of well integrity failure is low. The mechanical integrity of the wells will be demonstrated annually using annulus pressure tests (APTs), mechanical integrity tests (MITs), and/or approved cased-hole wireline logging tools (differential temperature survey).
- Additionally, the annulus system will be continuously monitored to detect for the potential loss of integrity.
- Due to this robust system of monitoring and rapid leak detection, the severity and impact of such an incident is expected to be minor. Therefore, it is expected that a loss in injection well integrity will not provide an imminent risk to human health, resources, or infrastructure.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours.
- Close the wellhead valve.
- Monitor the well(s) and annulus pressures.
- Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone.
- Pull and replace the tubing or the packer.
- Install a chemical sealant barrier and or attempt a cement squeeze to block leaks.
- Demonstrate mechanical integrity per the methods discussed in *Section 5– Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

Response Personnel:

- The initial personnel responsible for monitoring well integrity will be site personnel involved with the well operations.
- Environmental, Health, and Safety manager
- Drilling manager

- If well integrity has been lost, additional personnel such as engineering and remediation specialists will be consulted to determine the extent of the problem and establish a path/solution.

Equipment:
- The equipment involved in such remediation would likely range from the use of a workover rig, wireline investigative tools, pressure testing gauges, and other remedial equipment, to the potential replacement of the failed surface or downhole equipment, as deemed necessary.

8.4.6 Event Description – CO_2 Release to the Surface

Likelihood: Not Likely

This event could occur due to mechanical and integrity failures of distribution and storage facilities, unidentified orphan wells, well integrity issues, operating equipment over designed pressures, and geological complications.

Severity and Risk:
- Degree of risk: Major Emergency (Table 8-1)
- The design robustness will be the main mitigation against CO_2 leakage to surface—which makes the risk level low. While the USDW will not be affected by a potential topside failure, it does pose a risk to personnel.

Prevention and Detection:
- Proper operation and preventive maintenance of all surface facility equipment will be carried out.
- Due diligence will be exercised when collecting information from offset wells in the AOR, as discussed in *Section 3 – Area Of Review And Corrective Action Plan*.
- Pressure and rate monitoring, pressure falloff tests, annulus pressure tests, etc., will all be performed according to *Section 5 – Testing and Monitoring Plan*.
- CO_2 plume monitoring will be performed per *Section 5– Testing and Monitoring Plan*.
- Tubing and annular pressures will be monitored and maintained below the maximum allowed values.
- The surface wellhead tree will be regularly maintained and tested for integrity.
- The subsurface back pressure safety valve will be regularly tested.

Potential Response Actions:
- Stop the injection and notify the Commissioner within 24 hours.
- The downhole check valve will close with a loss of pressure at the surface.
- Close the wellhead valve.
- Evacuate personnel from the facility and begin gas monitoring operations.
- Allow pressure to bleed off the equipment and process system and allow atmospheric gas

levels to return to normal.
- Determine the cause and severity of the failure to initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5– Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

Response Personnel:
- Site personnel involved with the injection operations
- Environmental, Health, and Safety manager
- Technical consultants, remediation experts, and local health authority

Equipment:
- The type of equipment involved in remediation would depend on the type and severity of the failure.

8.4.7 Event Description – Entrained Contaminant (Non-CO_2) Releases

Likelihood: Not Likely

This event could occur due to changes in contamination levels in the CO_2 source. Equally, microbial activity may allow for possible production of H_2S gas. These sources of contaminants may impact dissolution, geochemical reactions, and wellbore integrity.

Severity and Risk:
- Degree of risk: Minor to Serious Emergency (Table 8-1)
- The risk of changes in the CO_2 stream is low. Constant sampling will be conducted at the injection source and controls put in place to prevent this event.
- Should an unlikely event occur, the severity of the incident could range from minor to serious, depending on the length of time before the problem is detected.

Prevention and Detection: Samples of the CO_2 stream will be collected from the injection source pipeline. The samples, representing injection conditions, will be sent to a third-party laboratory for analysis. The analysis will be used to indicate contaminant levels.

Potential Response Actions:
- Lower the injection rates or stop the injection.
- Notify the Commissioner within 24 hours.
- Determine the cause of contaminants.
- Investigate downhole issues.
- Remediate the source of contaminants.
- Chemically treat the stream to reduce the effect of contaminants.
- Replace tubing and packer if necessary.

- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

Response Personnel:
- Site personnel involved with the injection operations
- Environmental, Health, and Safety manager
- Technical consultants and local health authority

Equipment:
- The type of equipment involved would depend on the type and severity of the issue.

8.4.8 Event Description – Accidents/Unplanned Events

Likelihood: Not Likely

Unforeseen events such as surface infrastructure damage, a pipeline leak, pump/compressor failure, or boater or animal damage may occur.

Severity and Risk:
- Degree of risk: Minor to Serious Emergency (Table 8-1)
- Very low risk of occurrence
- Should an unlikely event occur, the severity of the incident could range from minor to serious.

Prevention and Detection:
- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed and markers placed to alert the general public of the potential hazards. The markers will include the name of the operator and telephone number.
- Barricades will be installed to prevent accidental damage to any equipment, and to prevent animals from entering the facility.
- Weather will be continuously monitored and, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:
- Stop the injection and notify the Commissioner within 24 hours.
- The downhole check valve will close with a loss of pressure at the surface. Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.
- Notify the Commissioner when injection can be expected to resume.

Response Personnel:

- Site personnel involved with the injection operations
- Environmental, Health, and Safety manager
- Technical consultants and local health authority

Equipment:

- The type of equipment involved would depend on the type and severity of the issue.

8.4.9 Event Description – Natural Disaster

Likelihood: Likely

A moderate to severe hurricane and other natural disasters (e.g., earthquake, tornado, forest fire, or lightning strike) could temporarily affect operations of the surface and monitoring facilities.

Severity and Risk:

- Degree of risk: Major Emergency (Table 8-1)
- The risk of a weather-related disaster occurring within the project area is high.
- The risk of a moderate to severe earthquake occurring within the project area is very low.
- The impact severity could range from a minor event to a major one for all natural disasters.

Prevention and Detection:

- Equipment will be maintained regularly to prevent or minimize damage.
- Damage-prevention infrastructure will be installed and markers placed to alert the general public of the potential hazards. The markers will include the name of the operator and telephone number.
- Electronics and other water-sensitive equipment will be installed at an elevation to prevent submersion.
- Safety shutdown systems will be employed to minimize impact.
- Weather will be continuously monitored and, during the possibility of an adverse event, precautions will be taken to limit the potential impact.

Potential Response Actions:

- Stop the injection and notify the Commissioner within 24 hours.
- The downhole check valve will close with a loss of pressure at the surface. Check for additional hazardous conditions that may have resulted from the natural disaster.
- Determine the accessibility to the injection and monitoring wells.
- Perform safety checks for all personnel regarding hazards.
- Determine the cause and severity of the failure and initiate repairs.
- Demonstrate mechanical integrity per the methods discussed in *Section 5 – Testing and Monitoring Plan*.

- Notify the Commissioner when injection can be expected to resume.

Response Personnel:

- Site personnel involved with the injection operations
- Environmental, Health, and Safety manager
- Technical consultants and local authorities

Equipment:

- The type of equipment involved would depend on the type and severity of the issue.

8.5 Training

Personnel will be trained on their duties and responsibilities related to these facilities during annual on-site and/or tabletop training exercises. All plant personnel, visitors, and contractors must attend a plant overview orientation before entering any of the facilities. A refresher course on this training is required annually for all personnel.

Lapis will provide a copy of the Emergency Response Plan to local first responders that includes potential response scenarios.

8.6 Communications Plan and Emergency Notification Procedures

Emergency response contacts for St. Charles Parish are as follows:

Table 8-2 – Emergency Services – **CALL 911**

Agency	Telephone Number
Bayou Gauche Fire Department (District #9)	911 or 985-758-7405
St. Charles Parish Sheriff	911 or 985-783-6237
St. Charles Hospital	985-785-6242
St. Charles Office of Emergency Preparedness	985-783-5050
Louisiana Emergency Preparedness Office	225-763-3535
Louisiana State Police	504-310-7000
Louisiana State Police – Hazardous Material Hotline	877-925-6595

Table 8-3 – Government Agency Notification

Agency	Telephone Number
LDENR – Commissioner of Conservation	225- 342-5540
Louisiana Department of Energy and Natural Resources	225-342-5515
Injection Well Incidents	225-342-5515
Local Emergency Planning Committee (LEPC)	985-783-5050
National Response Center (NRC)	800-424-8802
Louisiana State Police – Hazardous Material Hotline	877-925-6595

Table 8-4 – Internal Call List

Name	Telephone Number
Lapis Operations	469-629-1766

As appropriate, Lapis will communicate with the public regarding events that require an emergency response, including the impact of the event on drinking water or the severity of the event, actions taken or planned, etc.

8.7 Flood Hazard Risk

Due to its location near the coast, the Libra project is designated as FEMA flood hazard Zone AE, which corresponds to a coastal area within the 1% annual chance flood event—with additional hazards due to storm-induced velocity wave action. Floodplain management standards apply. See *Appendix G-1* for a map detailing the FEMA flood zone hazard detail.

8.8 Emergency Response Plan Review and Updates

This Emergency Response Plan will be reviewed and updated annually. Any amendments to the plan must be approved by the Commissioner and will be incorporated into the permit when one of the following occurs:

- Within 1 year of an AOR evaluation
- Following any significant changes to the facility, such as the addition of injection or monitoring wells
- Change in personnel
- As required by the Commissioner

The following attachments are located in *Appendix G*:

- Appendix G-1 FEMA Flood Zone Hazards Map
- Appendix G-2 Map of the AOR Showing Resources and Infrastructure

SECTION 9 – FINANCIAL ASSURANCE

TABLE OF CONTENTS

Figures

9.1 Facility Information

Project Name: Libra CO_2 Storage Solutions Project

Company Name: Lapis Energy (LA Development), LP

Project Contact:

Brandon Anderson, Libra Project Manager
Lapis Energy (LA Development), LP
5420 LBJ Fwy, Bldg. 2
Suite 1330
Dallas, Texas 75240
469-629-1766 / permitting@lapisenergy.com

Well Locations: St. Charles Parish, Louisiana

Simoneaux CCS Injector Well No. 001
Latitude: 29° 48' 35.315" N (North American Datum of 1927 (NAD 27))
Longitude: 90° 22' 17.226" W (NAD 27)

Simoneaux CCS Injector Well No. 002
Latitude: 29° 48' 35.317" N (NAD 27)
Longitude: 90° 22' 17.510" W (NAD 27)

Simoneaux CCS Injector Well No. 003
Latitude: 29° 48' 35.319" N (NAD 27)
Longitude: 90° 22' 17.793" W (NAD 27)

Lapis Energy (LA Development), LP (Lapis) is providing this financial responsibility proposal pursuant to Statewide Order (SWO) 29-N-6 and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.85**

Lapis has researched financial instrument alternatives and intends to implement surety bonds or trust instrument(s) to cover (1) the costs of corrective action, (2) injection well plugging, and (3) post-injection site care and site closure. For emergency and remedial response, Lapis intends to secure a site pollution insurance policy crafted to meet the Company's project-specific needs and Commissioner of Conservation (Commissioner) requirements.

The estimated costs of each of these activities, as provided by a third party with knowledge of industry standards and utilizing current U.S. dollar values, are presented in Table 9-1.

Figure 9-1 – Cost Estimates for Activities to be Covered by Financial Responsibility

Activity	Total Cost ($)
Corrective Action	$15,953,750
Injection Well Plugging	$1,330,000
Post-Injection Site Care and Site Closure	$4,245,000
Emergency and Remedial Response	$20,000,000

The explanation of the cost estimates listed in Table 9-1 are as follows:

Corrective Action – The estimate is $15,953,750 in today's dollars. Based on the Corrective Action Plan presented in *Section 3 – Area of Review and Corrective Action Plan*, Lapis will be conducting the entirety of the corrective action scope after injection has begun. Lapis is proposing to issue a surety bond to address this exposure.

Plugging Injection Wells – An itemized third-party estimate is provided through the Geologic Sequestration Data Tool as confidential information. The plugging estimate of the project wells is $1,330,000 in today dollars.

Post-Injection Site Care and Site Closure (PISC) – The cost exposure of PISC is $4,245,000 in today's dollars. Lapis is permitting the PISC activities to begin 20 years after the commencement of operations. Lapis is proposing to issue a surety bond, or multiple bonds separately, if necessary, to address this exposure.

Emergency and Remedial Response – Lapis has quantified multiple worst-case scenarios, addressing numerous outcomes and risk-ranked each accordingly. A copy of the Risk Matrix is included in *Appendix I-1*. The total combined cost, based on the risk ranking of each scenario, is $15,900,000 in today's dollars. Lapis is proposing to financially assure against the worst of the risk-ranked scenarios at a value of $20,000,000 with a site pollution insurance policy.

9.2 Lapis Energy (LA Development), LP – Class VI Applicant overview as designated Developer of Libra CO2 Storage Solutions LLC

From the 2023 Ernst & Young LLP financial audit of Lapis Energy Holdings, LP

Lapis Energy Holdings LP and its subsidiaries (the Company) was formed on November 24, 2021 for the purpose of originating, developing and implementing industrial de-carbonization projects that capture, transport and sequester or store carbon dioxide, known as the Carbon Capture and

Storage or "CCS" industry, and other greenhouse gases including related low carbon projects such as clean hydrogen. [redacted] *is the primary source of funding to the Company to support the Company's development efforts. The Company is still in the origination phase of developing and implementing projects.*

Lapis Energy (LA Development) LP is a wholly owned subsidiary of Lapis Energy Holdings.

Lapis has been capitalized to date with equity funding by certain members of the management team and [redacted], a dedicated investment vehicle controlled by [redacted], a growth-oriented, middle market-focused private equity firm with more than $1.6 billion of assets under management, that invests in sustainable and conventional energy, industrial materials, and agricultural infrastructure.

Lapis Energy (LA Development) LP is the Class VI Permit applicant on behalf of Libra CO2 Storage Solutions LLC, which is detailed below.

9.3 Financial Backing of Libra CO_2 Storage Solutions LLC

From the 2023 PwC financial audit of Libra CO2 Storage Solutions LLC

Libra CO2 Storage Solutions LLC was formed by Lapis Energy LP ("Lapis") as a special purpose entity to hold and develop pore space assets previously secured by Lapis under a Servitude Agreement with a landowner in St. Charles, Parish, Louisiana ("Servitude Agreement"). Effective June 7, 2023, the Company entered into a joint venture for the purpose of designing, implementing, and operating a carbon dioxide ("CO2") sequestration ("CCS") project at the site secured by the Servitude Agreement. The Company is still in the permitting phase of the project with Lapis serving as the Developer under the Development Services Agreement entered concurrent with the joint venture transaction.

Libra is owned 50/50 by Lapis Energy LP, a wholly owned subsidiary of the Lapis Energy Holdings LP parent entity, and an investor.

Under Libra's governing documentation, including the Development Services Agreement, Lapis as the "Developer" of Libra is authorized to submit this Class VI permit application. As a joint venture owner, Lapis will be the Developer through Class VI approval, the primary stage gate, for Lapis to submit a qualifying Financial Investment Decision ("FID") package to the Libra Board for approval. The Libra Board is comprised of two representatives from Lapis and two representatives from the investor.

9.4 Strategy and Milestones to Secure Financial Instruments

Lapis has reviewed the regulations and understands they must demonstrate financial responsibility to the Commissioner during the phases of the application and the project itself. As such, the Company has provided estimates and procured advice from attorneys, industry advisors, and insurance brokers who have direct experience with companies that have submitted Class VI permit applications—or are in the process of doing so—to address the following:

1. Corrective action on wells in the area of review (AOR)
2. Injection well plugging
3. Post-injection site care and site closure
4. Emergency and remedial response (ERR) activities

Further, management has referenced the Underground Injection Control (UIC) Class VI Program Financial Responsibility Guidance document.

With regard to Items 1, 2 and 3 above, the Company has entered into a General Indemnity Agreement with Ascot Surety and Casualty Company and a Financial Responsibility (or "Good Guy") letter with the same carrier for an amount of $29 million.

Figure 9-1 provides information from AM Best for Ascot Surety and Casualty Company, which is rated A (Excellent).

Figure 9-2 – Credit Rating Snapshot

Best's Credit Ratings

Financial Strength View Definition

Rating (Rating Category):	A (Excellent)
Affiliation Code:	g (Group)
Outlook (or Implication):	Stable
Action:	Affirmed
Effective Date:	September 28, 2023
Initial Rating Date:	April 18, 2022

Long-Term Issuer Credit View Definition

Rating (Rating Category):	a+ (Excellent)
Outlook (or Implication):	Stable
Action:	Affirmed
Effective Date:	September 28, 2023
Initial Rating Date:	April 18, 2022

Financial Size Category View Definition

Financial Size Category: XIII (USD 1.25 Billion to Less than 1.50 Billion)

Best's Credit Rating Analyst

Rating Office: A.M. Best Rating Services, Inc.

Financial Analyst: Billiah Moturi

Director: Erik Miller

Note: *See the Disclosure Information Form or Press Release below for the office and analyst at the time of the rating event.*

Disclosure Information

Disclosure Information Form
View AM Best's Rating Disclosure Form

Press Release
AM Best Affirms Credit Ratings of Ascot Group Limited's Core Operating Subsidiaries
September 28, 2023

View AM Best's Rating Review Form

Lapis' intent is to secure up to three bonds to address these assurance requirements, per guidance from the Company's insurance broker and communication with other brokers active in the carbon capture and sequestration (CCS) market. Lapsi will provide updated information related to their financial responsibility instruments annually to the Commissioner. Additionally, Lapis will review the financial assurance estimates for adjustments to inflation and cost adjustments annually, at least 60 days prior to the anniversary date of the instruments being established.

With regard to Item 4, Lapis procured a financial assurance letter from Alliant Insurance Services, Inc (Alliant). At this time, per recent guidance from Alliant based on the ERR cost estimate provided above, Lapis intends to secure insurance coverage for this exposure under a site pollution insurance policy with a limit of $16,000,000, at an annual premium estimated by our broker at $175,000 to $225,000 per annum, up to a limit of $20,000,000, at an annual premium estimated by our broker at $200,000 to $250,000 per annum.

This type of policy includes a Financial Responsibility and Reimbursement Endorsement manuscript that states, "Coverage hereunder shall only apply to the extent a Financial Assurance Claim is made by a regulatory agency to which the Insured is required to demonstrate financial responsibility pursuant to US EPA code 40 CFR 146.94." Figure 9-2 provides a snapshot of the wording that has been accepted by the EPA on various similar CCS projects.

Figure 9-3 – Legal Language of Financial Assurance Endorsement

A. REMEDIATION EXPENSES

To pay on behalf of the **Insured**:

Coverage A.1 - Onsite Pollution

1. **Remediation Expenses** incurred in accordance with the **Emergency and Remedial Response Plan** exclusively for remediation of **Pollutants** that are on or under a **Covered Property**.

Coverage A.2—Offsite Pollution

2. **Remediation Expenses** incurred in accordance with the **Emergency and Remedial Response Plan** exclusively for remediation of **Pollutants** that are beyond the boundaries of the **Covered Property.**
3. Coverage under Section **I.A.1** and **I.A.2** shall apply only if the **Insured** becomes legally obligated to pay such **Remediation Expenses** as a result of a **Financial Assurance Claim** which is first made against the **Insured** and reported to the Company in writing during the **Policy Period**, or during the **Extended Reporting Period** if applicable.

B. EMERGENCY RESPONSE EXPENSES

To pay on behalf of the **Insured**, **Emergency Response Expenses** incurred in accordance with the **Emergency and Remedial Response Plan** as a result of a **Financial Assurance Claim**. The **Emergency Response Expenses** must: **(i)** arise from a **Pollution Incident** that first commenced during the **Policy Period**; **(ii)** be in accordance with **Emergency and Remedial Response Plan**; and **(iii)** result from **Financial Assurance Claim** made by a regulator to whom the Company has furnished evidence of financial assurance. For this Coverage to apply, the **Pollution Incident** giving rise to the **Emergency Response Expenses** must be unexpected and unintended from the standpoint of the **Insured**.

The Company is maintaining flexibility to enter into alternative financial instruments and collateralization requirements or seek coverage from other insurance companies—as milestones are achieved and pay-in periods are defined—and will maintain open communication with the Commissioner throughout the permit approval process and beyond.

Financial assurance will be maintained until the Commissioner receives and approves the site closure plan and approves the site closure.

The following attachments are located in *Appendix I*:

Appendix I-1 Risk Matrix
Appendix I-2 [redacted]
Appendix I-3 [redacted]
Appendix I-4 [redacted]

SECTION 10 – ENVIRONMENTAL JUSTICE

TABLE OF CONTENTS

Figures

Tables

10.1 Executive Summary

Lapis Energy (LA Development), LP (Lapis) has conducted an environmental justice (EJ) analysis for the Libra CO_2 Storage Solutions Project (Libra), including identifying potential EJ risks near the area and, where appropriate, recommended mitigations in light of EPA and other EJ guidance.

The following conclusions have been made relative to the EPA's Memorandum on Environmental Justice Guidance for Underground Injection Control (UIC) Class VI Permitting and Primacy[1] issued in August 2023. Table 1-1 details these findings.

Table 10-1 – Findings Regarding EPA's EJ Guidance for UIC Class VI Permitting and Primacy

EPA's EJ Guidance	Findings of Libra's EJ Analysis
1. Identify communities with potential EJ concerns.	The EPA's Environmental Justice Screening and Mapping Tool (EJScreen) did not identify potentially vulnerable communities within the screening area.
2. Enhance public involvement.	Lapis has prepared a stakeholder map and engagement plan to support meaningful and transparent engagement with neighboring communities and the wider public. The project is located in a remote area on private land, and uniquely designed to have minimal community impacts. There are, however, opportunities for the Libra project to maximize community benefits outside of the screening area, and this will be a key opportunity for public involvement.
3. Conduct appropriately scoped EJ assessments.	Lapis' EJ analysis did not identify traditionally underserved or vulnerable communities in the screening area. Lapis will evaluate the need for additional assessments as the project progresses.
4. Enhance transparency throughout the permitting process.	Lapis has been increasing its presence in St. Charles Parish in lockstep with the project's progress and is currently engaged with local elected officials, first responders, local schools, and other key stakeholders. The company will increase these engagements during the permitting process, working to ensure that local community

[1] U.S. Environmental Protection Agency (2023). Environmental Justice Guidance for UIC Class VI Permitting and Primacy. https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf

EPA's EJ Guidance	Findings of Libra's EJ Analysis
	members are engaged and informed, and that any concerns are promptly addressed. In addition to face-to-face local engagements, Lapis will maintain a project-specific webpage, where it will post updates on the project.
5. Minimize adverse effects to Underground Sources of Drinking Water (USDWs) and the communities they may serve.	This Class VI permit application provides detail on the protection of USDWs, as well as emergency response protocols (*Section 8 – Emergency and Remedial Response Plan*) to ensure public safety, were an incident to occur.

The overall finding of the EJ analysis is that the Libra project is not located in an area with specific EJ-related concerns and poses minimal risk to neighboring communities—primarily due to the remote site location on private land.

10.2 Introduction

This section of the application summarizes EJ analysis findings at the potential injection site and a surrounding 2.5-mile (mi) radius buffer generated at each site, hereafter referred to as the "screening area." It is important to note that this screening area is larger than the official area of review (AOR) for the Libra project, but is used in this analysis for the purpose of identifying the fullest possible range of EJ conditions in the proximate area. Methods to identify EJ conditions include utilizing EJScreen and the Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST), as well as supplemental information where needed.

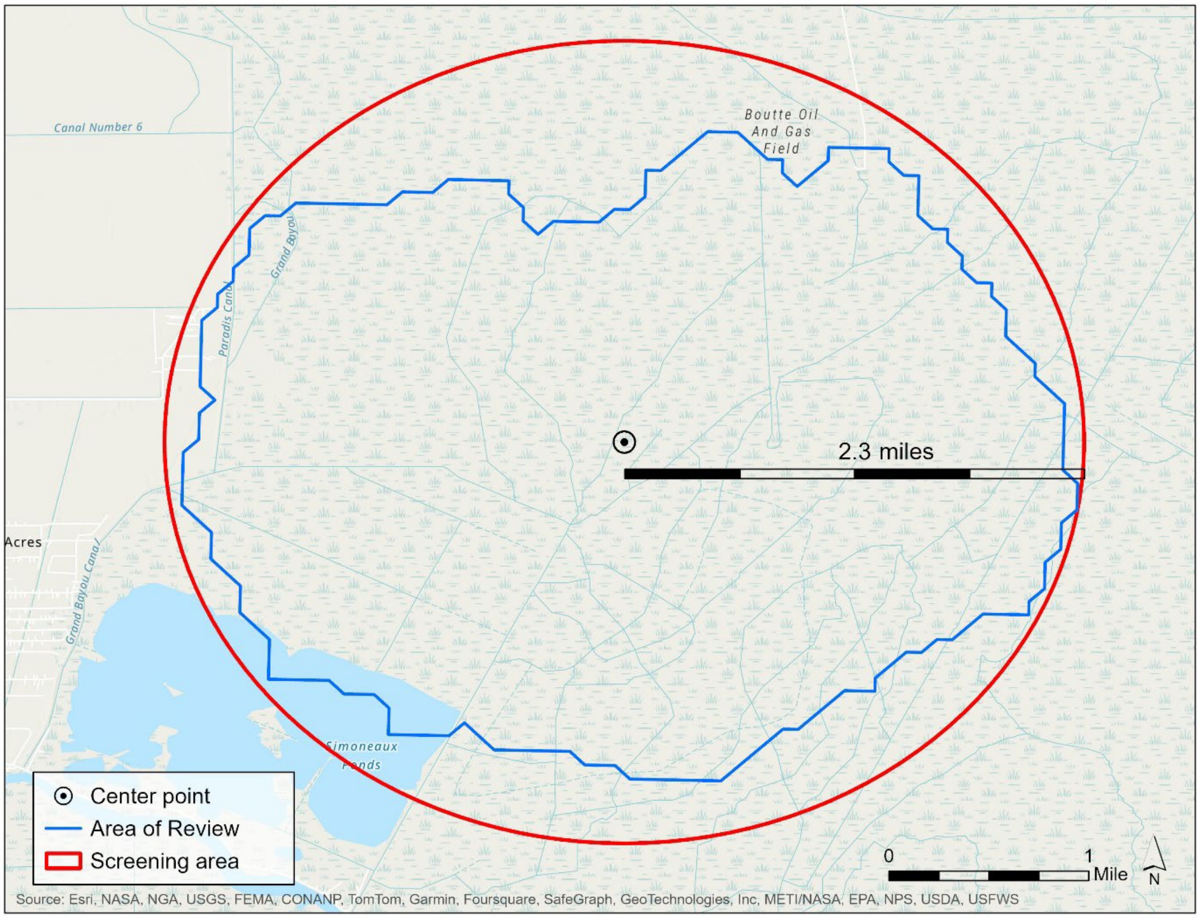
This analysis aims to align with EPA guidance on the Class VI injection well permitting process and its recommended inclusion of EJ considerations in the UIC Program.[2] As defined by the EPA, EJ is "the fair treatment and meaningful involvement of all people during the development, implementation, and enforcement of environmental laws, regulations, and policies, regardless of race, color, national origin, or income."[3]

10.3 Review of Site Characteristics

EJScreen was used to assess the EJ conditions within the screening area. According to the EJScreen findings, this screening area encompasses 1,705 people spread over 72.40 square miles (sq mi).

[2] U.S. Environmental Protection Agency (2011). Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide. https://acrobat.adobe.com/link/review?uri=urn:aaid:scds:US:61274165-1df1-3ee2-a4a7-dded892e5b5b
[3] U.S. Environmental Protection Agency (2023). Learn About Environmental Justice. https://www.epa.gov/environmentaljustice/learn-about-environmental-justice

Figure 10-1 presents the screening area along with the AOR for the Libra project's proposed injection wells.



Map generated by Acorn International, LLC.

Figure 10-1 – Screening Area and AOR

To gauge the EJ conditions within the screening area, Lapis replicated the area within the most recent version of EJScreen (Ver. 2.3). This tool presents socioeconomic and environmental data within the screening area that indicates areas of potential EJ concern. When using EJScreen, the EPA recommends using the 80th percentile nationally for the "EJ Indexes" as a benchmark for identifying areas where further consideration, analysis, or outreach is potentially warranted.[4] That is, if any of the EJ Indexes within the screening area are at or above the 80th percentile nationally, then further review may be needed. Reaching this benchmark means that only 20% of the U.S. population measures a higher value for that respective indicator. However, it does not automatically designate an area as an EJ community.

[4] U.S. Environmental Protection Agency (2022). EJScreen Technical Documentation. https://www.epa.gov/sites/default/files/2021-04/documents/ejscreen_technical_document.pdf

An initial review of site characteristics within the screening area indicates the following, relative to EJ considerations:

- There are no sensitive receptors, including schools or hospitals, identified within the screening area according to Google Earth analysis and findings from the EJScreen report.
- There are two places of worship located within the area, according to the EJScreen report.
- There are no American Indian Reservation Lands found within the area.

10.3.1 EJ Indexes

The 13 EJ Indexes included in EJScreen combine socioeconomic information with an individual environmental indicator (toxic releases, ozone, etc.) to pinpoint communities where high environmental burdens and vulnerable communities are present.[5] The results are summarized in Table 10-2.

Table 10-2 – EJ Indexes within the Screening Area

Proposed Injection Well and 2.5-mi Screening Area (Population: 1,705 Area in 72.40 sq mi)			
Category	**Selected Variables**	**% in State**	**% in USA**
EJ Index	EJ Index for Particulate Matter 2.5	10	18
EJ Index	EJ Index for Ozone	19	16
EJ Index	EJ Index for Nitrogen Dioxide (NO_2)	3	3
EJ Index	EJ Index for Diesel Particulate Matter	12	10
EJ Index	EJ Index for Toxic Releases to Air	21	30
EJ Index	EJ Index for Traffic Proximity	12	8
EJ Index	EJ Index for Lead Paint	20	17
EJ Index	EJ Index for Superfund Proximity	0	0
EJ Index	EJ Index for Risk Management Plan (RMP) Facility Proximity	26	33
EJ Index	EJ Index for Hazardous Waste Proximity	18	19
EJ Index	EJ Index for Underground Storage Tanks	16	29
EJ Index	EJ Index for Wastewater Discharge	14	18
EJ Index	EJ Index for Drinking Water Non-Compliance	0	0

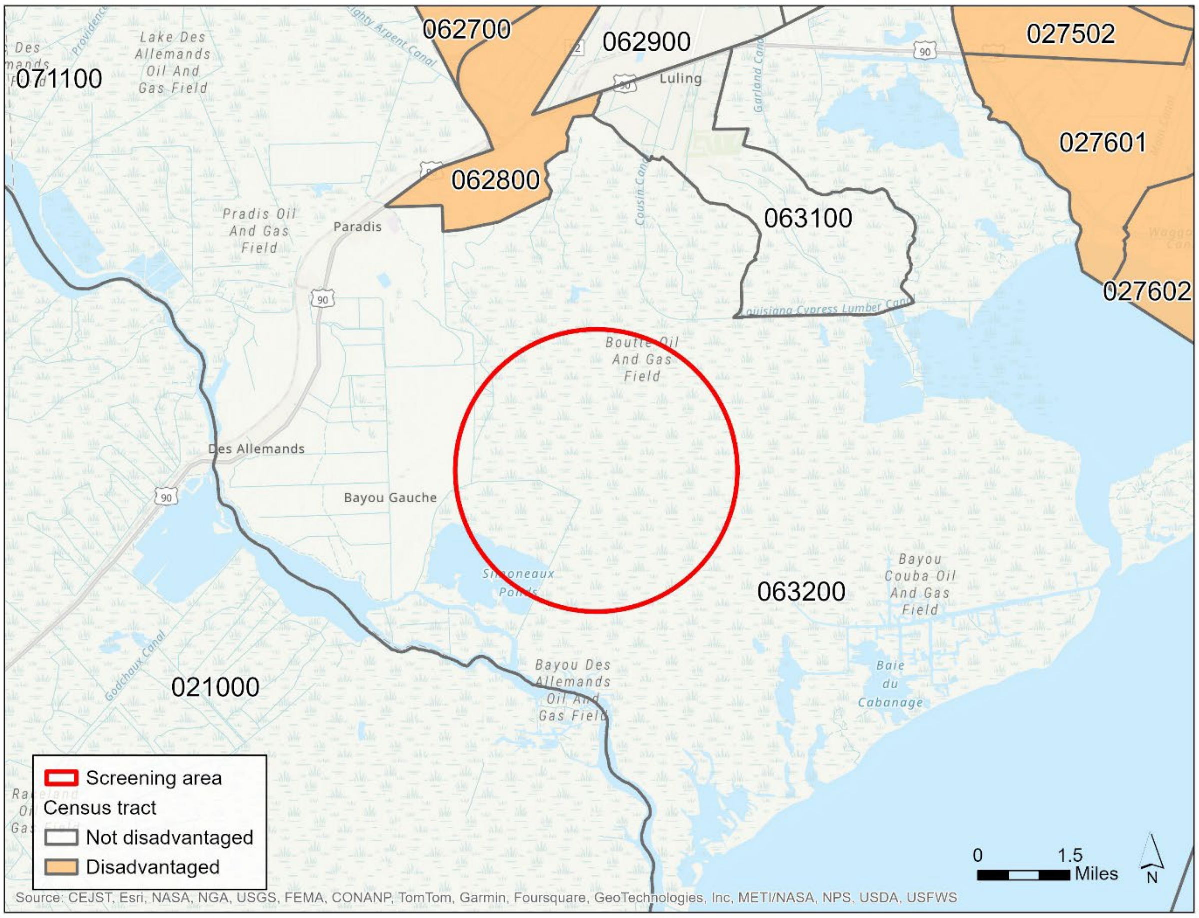
Source: EPA EJScreen

No indicators exceed the EPA's suggested benchmark throughout the screening area, which indicates that all of the above-referenced variables are within acceptable limits according to the EPA's standard. However, critical service gaps regarding transportation and "food deserts" may warrant further attention.

[5] U.S. Environmental Protection Agency (2023). EJScreen Fact Sheet. https://www.epa.gov/system/files/documents/2023-06/ejscreen-fact-sheet.pdf

10.3.2 Socioeconomic and Demographic Data

To identify low-income and disadvantaged areas, the EPA recommends utilizing the Justice40 CEJST, which evaluates disadvantaged communities according to Census tracts instead of parishes[6] (Figure 10-2). According to CEJST, Tract 063200 in St. Charles Parish is not classified as a disadvantaged community.



Map generated by Acorn International, LLC.
Note: Census tract boundaries are from 2019.

Figure 10-2 – CEJST Disadvantaged Communities Near Injection Wells

In addition to EJScreen, the U.S. Census Bureau provides publicly available socioeconomic and demographic information near the screening area.[7] Census data from each Census tract intersected by the screening area is summarized in Table 10-3.

Table 10-3 – Data of Census Tracts Intersected by Screening Area

[6] U.S. Environmental Protection Agency (2023). Benefits Analyses: Low-Income and Disadvantaged Communities. https://www.epa.gov/system/files/documents/2023-05/LIDAC%20Technical%20Guidance%20-%20Final_2.pdf
[7] U.S. Census Bureau (2022). American Community Survey. 5-Year Estimates.

	United States		Louisiana		Census Tract 063200	
Label	**Est.**	**%**	**Est.**	**%**	**Est.**	**%**
Total population	331,097,593	(X)	4,640,546	(X)	4,297	(X)
Median age (years)	38.5	(X)	37.6	(X)	38.7	(X)
Hispanic or Latino (of any race)	61,755,866	18.7%	255,584	5.5%	117	2.7%
White	218,123,424	65.9%	2,758,714	59.4%	3,864	89.9%
Black or African American	41,288,572	12.5%	1,464,582	31.6%	118	2.7%
American Indian and Alaska Native	2,786,431	0.8%	24,952	0.5%	74	1.7%
Two or more races	29,142,780	8.8%	225,187	4.9%	241	5.6%
High school graduate or higher	202,001,294	89.1%	2,706,792	86.7%	2,504	87.3%
Bachelor's degree or higher	77,751,347	34.3%	815,569	26.1%	449	15.7%
Median household income (dollars)	$75,149	(X)	$57,852	(X)	$100,078	(X)
Poverty rate (individual)	(X)	11.1%	(X)	18.6%	(X)	(X)
With Social Security	39,273,890	31.2%	558,430	31.6%	497	31.8%
With retirement income	29,084,404	23.1%	373,171	21.1%	253	16.2%
With cash public assistance income	3,339,152	2.7%	35,241	2.0%	0	0.0%
With food stamp/SNAP benefits in the past 12 months	14,486,880	11.5%	283,574	16.1%	192	12.3%
Unemployment rate (civilian labor force)	7,861,214	7,861,214	126,809	126,809	35	35

Source: U.S. Census Bureau (2022)

All data referenced in the commentary in this section originates from the Census unless otherwise specified. According to the U.S. Census American Community Survey 2022, the total population of Louisiana is 4,640,546, which highlights how relatively small the Census tract's population is, with an estimated population of 4,297.

In Louisiana, the average age of the population is 37.6, which trends slightly below the Census tract (-1.1%) and Louisiana (-0.9%). Looking at race and ethnicity, the data indicates that most of the population across Louisiana (59.4%), including the Census tract area (89.9%), is white alone.

According to the Census data, 86.7% of the Louisiana population has graduated from high school, and 26.1% have a bachelor's degree or higher. In the Census tract area, the percentage of residents with at least a high school degree is above the state's, at 87.3%, whereas the rate of residents obtaining at least a bachelor's degree is lower, at 15.7%.

The median household income in the Census tract area ($100,078) surpasses the median household income for the United States ($75,149) and Louisiana ($57,852). Although educational attainment rates are higher in Louisiana, the median household income is significantly higher in the Census tract area.

10.4 Considerations on Environmental Justice Impacts

EJScreen did not identify any areas that exceeded the suggested 80th percentile national benchmark. The Libra project's remote location does not lend itself to disproportionately benefitting or impacting some populations over others.

Providing equitable access to up-to-date and factual project information is a key priority for Lapis, recognizing that the project will not be visible to neighbors and that carbon sequestration will be new to many in the area. Lapis will regularly attend and/or host community meetings and maintain a visible presence in the community through its community investment activities and execution of its stakeholder engagement plan.

The following attachments are located in *Appendix J*:

- Appendix J-1 Lapis Libra EJScreen