CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Rapides One CCS Site

Contents

1.0 Project Background and Contact Information

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CapturePoint Solutions, LLC (CPS) is a privately owned Texas based company with a focus on developing large scale carbon dioxide capture and sequestration projects with an emphasis on deep geologic storage of CO_2 in saline formations. CPS is a fully owned subsidiary of CapturePoint LLC, which has over one million tons of anthropogenic CO_2 capture, 300+ miles of CO_2 pipelines and multiple CO_2 EOR floods including two EPA approved MRV plans and existing projects that benefit from Federal 45Q tax credits. CapturePoint LLC is also a licensed oil and gas well operator in the state of Louisiana.

The proposed Rapides One CCS ([redacted]) carbon dioxide geologic storage site is in the [redacted] portion of Rapides Parish, Louisiana, approximately [redacted] The project will consist of [redacted] injection wells and four monitoring wells. The site is in [redacted]. The expected maximum daily injection rate for the site is [redacted]. [redacted].

The injection capacity is expected to grow from [redacted] to about [redacted]. It is anticipated this site will last for 20 to 25 years and will cumulatively sequester about [redacted] metric tonnes over the life of the project. Initially CPS will use the site to capture CO_2 from the [redacted]. The medium-term plan is to connect it to the Gulf coast sources. The first set of injection is projected to happen in 2024 after securing the Class VI injection permit. The pipeline and capture infrastructure will be developed in parallel based on the initial progress and feedback on this Class VI permit application.

The modeled pressure front that delineates the Area of Review (AoR) and maximum plume extent are shown on Figures 2-22, 2-22a (injection zone 1), 2-22b (injection zone 2) and 2-22c (injection zone 3). Based on preliminary modeling and simulation the estimated maximum subaerial extent of the largest of the three CO_2 plumes (Sparta) is approximately [redacted] acres (Figure 2 in Module E "*Post Injection Site Care and Site Closure Plan*"). Following the drilling, coring and logging of a stratigraphic test well, modeling and simulation will be revised to update the aerial extent of the AoR (additional information is located in Module B "*AoR and Corrective Action Plan*" and in Module D "*Pre-Operation Testing Pan*").

The proposed project site in Rapides Parish, Louisiana was selected based on a culmination of factors deeming it to be an ideal candidate for a Geological Sequestration project. Both the confining layers and targeted injection zones are subaerially extensive throughout the Gulf Coast Region. A series of thick (200' to 800') confining layers separate shallow (0' to 2,100') groundwater resources (USDWs) from the deeper (4,250' to 9,800') injection zones (see Type Log Figure 2-2 in Site Characterization). Available data indicate that there are no transmissive faults or fractures within the AoR and that the site is in a very stable seismic region of the Gulf Coast (see figure 2-57 in Site Characterization). There are only three existing artificial penetrations within the designated AoR and these will be mitigated through appropriate corrective action. Groundwater use is limited to shallow aquifers penetrated by four abandoned groundwater wells and nine active shallow groundwater wells.

The injection zones consist of the [redacted].
Each of the three target injection formations are capped by thick, 200 to 800-foot-thick confining units. In

descending order these are the [redacted] (see Figure 2-1 in Site Characterization). The primary confining unit is the regionally extensive [redacted]. Total thickness of all confining zones of over 1,250 feet thick. There is total of [redacted] proposed injection wells, two per layer with the volumes per well varying from [redacted] each for the two [redacted] wells. The [redacted] will act as the primary and largest injection zone. The injected CO_2 will be collected from anthropogenic sources including ethanol, gas processing, fertilizer and ammonia plants from the Haynesville basin and Gulf Coast. This CO_2 will be transported to the site via a pipeline network. All surface facilities for the site will be constructed on private property owned or leased by CPS.

Permitting and oversight for this project will be through the US Environmental Protection Agency (USEPA), [redacted] the Louisiana Department of Natural Resources (LADNR). The site will be owned and operated by CapturePoint Solutions, LLC (CPS). As part of the permitting and oversight, CPS will continuously monitor operations at surface facilities and at each of the injection wells and provide collected data to the USEPA in semi-annual reports.

Amended plans or demonstrations per this permit application shall be submitted to the UIC Program Director as follows:

1) Within one year of an Area of Review (AoR) reevaluation
2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the AoR, on a schedule determined by the UIC Program Director, or
3) When required by the UIC Program Director.

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

2.0 Site Characterization

A detailed Site Characterization report was prepared and accompanies this permit application below in Section 2.0 pursuant to 40 CFR 146.82(a)(2), (3), (5), and (6). This Site Characterization provides information including regional and local geology, geohydrology, hydrology, geologic structure, characterization of the confining and injection zones of interest and discussion of USDW's within the AoR. Maps, cross sections and other pertinent figures are included as attachments to this narrative. References to figures and tables are included in the narratives. References to rules, sections and figures are listed in **Table 1**.

Table 1. Site Characterization Sections, Rules and References

Section and Rules	Reference
Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]	Figures 2-19, 2-39 and 2-52 in Site Characterization
Maps and Cross Sections of the Aor [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]	Figures 2-2 (AoR) and 2-5 (Regional cross section)
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]	Site Characterization section 2.2.4
Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]	Site Characterization section 2.3
Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]	Site Characterization section 2.6
Seismic History [40 CFR 146.82(a)(3)(v)]	Site Characterization section 2.5
Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]	Site Characterization section 2.4
Geochemistry [40 CFR 146.82(a)(6)]	Site Characterization section 2.7
Other Information	N/A

Site Characterization: List of Appendices:

Appendix A Figures Regional Geology Cross Section and Maps

Appendix B Figures Local Geology Cross Sections and Maps

Appendix C Figures Maps of Wells within the AoR

Site Characterization: List of Tables:

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Site Characterization: List of Figures Continued:

Site Characterization: List of Figures Continued:

2.0 Site Characterization Narrative

The geologic suitability of a specific stratigraphic interval for the injection and confinement of carbon dioxide (CO_2) is determined primarily by the following criteria:

- Lateral extent, thickness, porosity, and permeability of the Injection Zone;
- Lateral extent, thickness, porosity, and permeability of the overlying Confining Zone;
- Faulting or fracturing of injection zones, overlying aquicludes, or confining zone; and
- Seismic risk analysis.

These criteria can be evaluated based on the regional and local depositional and structural histories of the geologic section.

In the following sections, the depositional and structural framework of the sedimentary column (Figure 2-1) utilized for the sequestration of CO_2 for CapturePoint Solutions at the central Rapides Parish site are outlined. Information is obtained from the regional and local data interpretations and conclusions of the area of review (AoR) study, published literature reviews, as well as available logs and core data for the site. A type log of the formations beneath the Rapides site using the nearest offset log to penetrate the formation is contained in Figure 2-2. The key regulatory intervals are reported in true vertical depth (TVD) and sea level (SSL).

2.1 Regional Geology

The earliest record of sedimentation in the Gulf of Mexico Basin occurred during the Early to Middle Jurassic period, between 200 and 160 million years ago. At this time, the early phases of continental rifting resulted in the deposition of non-marine red beds and deltaic sediments (shales, siltstones, sandstones, and conglomerates) that composed the Eagle Mills Formation in a series of restricted, graben fault-block basins (Figure 2-3). These sediments were overlain by a thick sequence of anhydrite and salt beds (Werner Anhydrite and Louann Salt) deposited during Middle Jurassic time.

The deposition of the Louann Salt beds was localized within major basins that were defined by the major structural elements in the Gulf Coast Basin. The clastic Norphlet Formation (sandstones and conglomerates) overlies the Louann Salt and is more than 1,000 feet thick in Mississippi but thins westward to a sandstone and siltstone across Louisiana and into Texas. Norphlet conglomerates were deposited in coalescing alluvial fans near Appalachian sources and grade downdip into dune and interdune sandstone deposited on a broad desert plain (Mancini et al., 1985). Although the Norphlet Formation is non-fossiliferous, based on dating of the overlying and underlying sequences, the Norphlet Formation is probably late Middle Jurassic (Callovian) in age (Todd and Mitchum, 1977).

Shallow-water carbonate and clastic rocks of the Smackover, Buckner, and Haynesville Formations and Cotton Valley Group were deposited over the Norphlet Formation from the Late Jurassic into the Late Cretaceous. Jurassic, non-skeletal, carbonate sands and muds accumulated on a ramp-type shelf with reefal buildups developed on subtle topographic highs (Baria et al., 1982). A high terrigenous clastic influx in eastern Louisiana and Mississippi occurred during deposition of the Haynesville and diminished westward where the Haynesville Formation grades into the Gilmer Limestone in East Texas. The top of the Jurassic occurs within the Cotton Valley Group, with the Knowles Limestone dated as Early Cretaceous (Berrasian) in age (Todd and Mitchum, 1977). The middle Cretaceous was a period of relative stability, reduced clastic influx and maximum eustatic seal level rise since the Carboniferous period enabling the development of extensive, shelf-edge reef complexes (Baria et al., 1982).

Tectonism in the western United States and northern Mexico (Laramide Orogeny) in the Late Cretaceous resulted in a large influx of terrigenous sands and muds (Washita-Fredericksburg and Tuscaloosa Formations) into the Gulf Coast Basin. This effectively shut off the production of carbonates, except in the Florida and Yucatan regions. Global eustatic sea level fall since mid-Cretaceous time in conjunction with the increased rate of terrigenous sediment influx has been cumulative greater than the rate of subsidence for the gulf coast basin. Therefore, significant progradation of the continental shelf margin has occurred since the Cretaceous.

During the Cretaceous post-rift stage, structural highs and lows were formed resulting in regional angular unconformities in the northern onshore Gulf of Mexico Basin in form of the Sabine Uplift and Monroe Uplift (Ewing, 2009). The Monroe Uplift and Sabine Uplift are bounded by deep basins; the East Texas Salt Basin - North Louisiana Salt Basin and North Louisiana Salt Basin – Mississippi Interior Salt Basin, respectively (Figure 2-4).

Mesozoic igneous activity of the onshore Northern Gulf of Mexico Basin was studied and discussed in several studies and local reports (Kose, 2013;; Kidwell, 1951; Moody, 1949;; Ewing, 2009;; Nichols et al., 1968). The Monroe Uplift has largest volume of magma and greatest compositional diversity in the Northern Gulf of Mexico Basin and at least four major igneous rock groups were defined so far: i) intermediate rocks; ii) alkaline rocks; iii) basalts; iv) lamprophyres (Ewing, 2009; Kidwell,1951). It is not well understood why igneous activity occurred but there appears to be a relation between igneous activity and the movement of the uplift in the Monroe Uplift area (Salvador, 1991; Kidwell, 1951).

During the Cenozoic era, the geometry of the deposition in the Gulf of Mexico Basin was primarily controlled by the interaction of the following factors:

1. Changes in the location and rates of sediment input, resulting in major shifts in the location of areas of maximum sedimentation.
2. Changes in the relative position of sea level, resulting in the development of a series of large-scale depositional cycles throughout Cenozoic time.
3. Diapiric intrusion of salt and shale in response to sediment loading.
4. Flexures and growth faults due to sediment loading and gravitational instability.

Early Tertiary sediments are thickest in the Rio Grande Embayment of Texas, reflecting the role of the ancestral Rio Grande and Nueces Rivers as sediment sources to the Gulf of Mexico. By Oligocene time, deposition had increased to the northeast, suggesting that the ancestral Colorado, Brazos, Sabine, and Mississippi Rivers were increasing in importance. Miocene time is marked by an abrupt decrease in the amount of sediment entering the Rio Grande Embayment, with a coincident increase in the rate of sediment supply in southeast Texas, Louisiana, and Mississippi. Throughout the Pliocene and Pleistocene Epochs, maximum depocenters of sedimentation were controlled by the Mississippi River and are located offshore of Louisiana and Texas.

Tertiary sediments accumulated to great thickness where the continental platform began to build toward the Gulf of Mexico, beyond the underlying Mesozoic shelf margin and onto transitional oceanic crust. Rapid loading of sand on water-saturated prodelta and continental slope muds resulted in contemporaneous growth faulting (Loucks et al., 1986). The effect of this syndepositional faulting was a significant expansion of the sedimentary section on the downthrown side of the faults. Sediment loading also led to salt diapirism, with its associated faulting and formation of large salt withdrawal basins (Galloway et al., 1982a).

Sediments of the Tertiary progradational wedges were deposited in continental, marginal marine, nearshore marine, shelf, and basinal environments and present a complex depositional system along the Texas Gulf Coast.

Overlying the Tertiary progradational wedges along the Texas Gulf Coast are the Pleistocene and Holocene sediments of the Quaternary Period. Pleistocene sedimentation occurred during a period of complex glacial activity and corresponding sea level changes. As the glaciers made their final retreat, Holocene sediments were being deposited under the influence of an irregular, but rising, sea level. Quaternary sedimentation along the Texas Gulf Coast occurred in fluvial, marginal marine, and marine environments.

2.1.1 Regional Maps and Cross Sections

The regional geology section contains sixteen maps and four cross sections. Table 2-1 contains the information on Maps and Cross Sections used in the regional evaluation. All figures are contained in Appendix A – Regional Maps and Cross Sections. The data evaluated extends approximately 20 miles out from center of the proposed injection site in Rapides Parish and are at a 1=4,000' scale. These maps have been generated using the IHS Petra software.

Additionally, some published literature used in the regional stratigraphy and structure review contained maps that have been reviewed. These additional maps are contained as "Figures" referenced within their respect description sections as follows. Figure 2-5 is a published regional cross section and index map from Eversull (1984) and is provided in this Class VI Application for CapturePoint Solutions Rapides Parish site. The north-south cross section F-F' illustrates the increase in the southernly regional dip towards the Gulf of Mexico. The large regionally extensive [redacted] Formation (proposed primary confining zone) is shallowest in the north (near surface) and deepens towards the south to at just above 10,000 feet in south central Louisiana.

2.1.2 Regional Stratigraphy

The general stratigraphy of the region is shown on a Stratigraphic Column shown on Figure 2-1. The regional stratigraphy is well documented and extensive throughout north and central Louisiana. In the Rapides area and the interior salt basin, there are 4 major seal level advances during the first 35 million years of the Cenozoic era. These eustatic events created the regional confining zones, the [redacted]. An Early through Mid Cenozoic Stratigraphic column displaying the central Gulf Coast distribution of Tertiary rocks within the U.S. Gulf Coast is contained in (Figure 2-6). Storage assessment units consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts representing periods of erosion or non-deposition.

The following sections only describe the regional formations that may be penetrated at the Rapides site. These formations are described in ascending order beginning with the Paleocene-aged Midway Group. Note: that for CapturePoint Solutions sequestration site in Rapides the proposed injection intervals are the [redacted] sandstones, were deposited between two rising eustatic sea level events. The upper confining unit is defined as the [redacted] Formation and the lower confining zone defined as the [redacted]. Both confining zones developed from the deposition of marine, marginal marine, and delta front shales and muds. Details on the proposed confining and injection zones are discussed in Section 2.3.

2.1.2.1 Midway Group

The Paleocene-aged Midway Group sediments were deposited during the first major Tertiary regressive cycle. The Midway shale is regional in extent, thickening from the East Texas Basin toward the Gulf of

Mexico. The Midway Group is a thick calcareous to non-calcareous clay, locally containing minor amounts of sand. Conformably overlying marine Cretaceous sediments within the Midway Group is the Clayton Formation. The faunal succession across the Upper Cretaceous/Tertiary boundary shows a sharp break in both macro-fauna and micro-fauna types, making it possible to accurately determine the base of the Tertiary in the Gulf Coast Basin (Rainwater, 1964a). At the beginning of the Tertiary, an epicontinental sea still covered most of the Mississippi Embayment, with the Clayton Formation being deposited in an open marine environment. The unit is generally less than 50 feet thick and is composed of thin marls, marly chalk, or calcareous clays (Rainwater, 1964a).

As the epicontinental sea became partially restricted in the Mississippi Embayment, the Porters Creek clay was deposited on the Clayton marl. Fossil evidence, although scarce, indicates a lagoonal to restricted marine environment for the Porters Creek Formation (Rainwater, 1964b). The Porters Creek Formation is composed mainly of massively bedded montmorillonite clay. Open marine circulation was re-established in the Mississippi Embayment during the deposition of the shallow marine Matthews Landing Formation. The Matthews Landing Formation was deposited above the Porters Creek clay in a shallow marine environment, and is composed primarily of fossiliferous, glauconitic shales with minor sandstone beds (Rainwater, 1964a).

A major regression marks the deposition of the late Paleocene Naheola Formation that overlies the Matthews Landing Formation. Uplift in the sediment source areas of the Rocky Mountains, Plains, and Appalachian regions supplied an abundance of coarse-grained fluvial sediments for the first time in the Tertiary. Sedimentation rates along the Gulf Coast exceeded subsidence rates and produced the first major regressive cycle during the Tertiary. Alluvial environments dominated throughout most of Naheola time. The Naheola Formation consists of alternating sand, silt, and shale, with lignite interbeds near the top of the unit (Rainwater, 1964a).

The upper contact with the overlying Wilcox Group is gradational. Wood and Guervara (1981) defined the top of the Midway as the base of the last Wilcox sand greater than 10 feet thick. Precise thickness of the Midway is difficult to measure because it often cannot be differentiated from the underlying upper Navarro Group (Upper Cretaceous) using electric logs but overlies the Selma Chalk. The Midway, upper Navarro Clay (also called Kemp Clay), and the Navarro Marl are generally grouped together during electric log correlations. These formations compose a low-permeability hydrologic unit in the regional area greater than 900 feet thick. The Midway-Navarro section serves as an aquiclude, isolating the shallower freshwater Eocene aquifers from the deeper saline flow systems except, perhaps, at fault zones and along flanks of salt domes where vertical avenues for flow may exist (Fogg and Kreitler, 1982).

Figure A.1 (in Appendix A) contains a regional isopach map of the Midway Shale generated by CapturePoint Solutions. This Paleocene isopach illustrates that the shale has a thickness ranging between 700 and 900 feet in Northeastern Vernon Parish and Northwestern Rapides Parish. The Vernon–Rapides embayment's depositional synclinal axis flanks the proposed sequestration site approximately 25 miles to the northwest. The locations of cross-section's A-A' "Dip" and B-B' Strike are denoted in blue and red, respective. The thinning of the Midway shale to the northwest and northeast confirms the Sabine uplift and Lasalle Arch were positive features during Paleocene deposition. The Midway shale is the lower confining interval for the proposed Rapides sequestration site.

In a regional published map from Hosman, 1996 (Figure 2-7) the Midway continues to thicken to greater than 2,000 feet towards the Gulf Coast at depths exceeding 14,000 feet. Outcrops of the Midway exist from north-central Alabama up into Tennessee in the east.

2.1.2.2 Wilcox Group

The Paleocene-aged Wilcox Group is a thick clastic succession that flanks the margin of the Gulf Coast Basin. The Wilcox fluvial systems flowed into and down the axis of the East-Texas basin, supplying deltas along the margin of the Gulf of Mexico. Except for minor episodes of thin clastic shelf deposition, the East Texas Basin ceased to be a marine basin during the Tertiary and Quaternary Periods, when major Eocene, Oligocene, Pliocene, and Pleistocene depocenters shifted toward the Gulf of Mexico (Fogg and Kreitler, 1981).

The marine clays of the underlying Midway Group grade upward into the fluvial and deltaic sediments of the Wilcox, which is composed of interbedded lenticular sands, mud, and lignite (Fogg and Kreitler, 1982). The Wilcox Group contains fluvial and deltaic channel-fill sand bodies distributed within in a matrix of lower permeability inter-channel sands, silts, clays, and lignites. Most of the sands are distributed in a dendritic pattern, indicating a predominately fluvial depositional environment (Fogg et al., 1983).

The Wilcox Group is composed of over 4,000 feet of shale and sandstone deposited primarily from the prograding Holly Springs Delta System (Figure 2-8). This is a major Gulf Coast prograding delta system sourced primarily from the ancestral Mississippi River that encompassed central Louisiana, and southern Mississippi (Galloway, 1968). The Wilcox Group is divided into the Lower, Middle, and Upper intervals with the semi-regional Big Shale Marker as the divide between the Upper and the Middle/Lower Wilcox sands. Figure A.2 (in Appendix A) contains a regional isopach map of the Big Shale showing that the thickness of the interval ranges between 30 feet to greater than 100 feet, towards the northwest and northeast in map view. Average thickness for the Big Shale is approximately 85 feet within the Area of Review (AoR) for this project. [redacted]. The Wilcox Big Sale served as a hydrocarbon seal on the south flank of the LaSalle Arch.

Figure 2-9 provides a published regional isopach and configuration map of the Wilcox Group from Hosman, 1996. The Wilcox deepens towards the Gulf of Mexico in bands parallel to the Gulf Coast. The Wilcox deepens past 12,000 feet onshore to much deeper intervals offshore. Thickness trends mimic the Mississippi Embayment in the northeast and thicken to the south and southwest at the front of the Holly Springs Delta System.

A regional isopach map of the Lower Wilcox was developed by Galloway in 1968 for central Louisiana and central Mississippi (Figure 2-10). This figure shows the thickness of the interval from base of the Big Shale to the top of the Midway Group. The thickest deposits are to the southeast, which indicates that the LaSalle Arch had impacts on the deposition and supply rates of sediment.

Although less well studied, the upper Wilcox Group is generally considered to be transgressive with locally regressive delta lobes deposited during a global rise in sea level. An increase in the carbonate content and glauconite content in upper Wilcox sediments suggests an increase in marine conditions as compared to lower Wilcox. An examination of Wilcox hydrocarbon producing trends in Louisiana and Mississippi led Paulson (1972) to conclude that the Wilcox is a transgressive sequence. The transgressive marine deposits of the Carrizo sands lie directly on top of the Wilcox sands and is considered part of the Wilcox Group. Generally, the Carrizo sands have better porosities and permeabilities than the underlying Wilcox sands.

Additional published maps by Groat and Hart (1980) mapped the Wilcox Group in the Rapides area. Their findings demonstrated a Carrizo-Wilcox sand rich clastic section of over 600 feet thick near the proposed sequestration site (Figure 2-11). It also demonstrates that the [redacted] averages 1,000 feet thick in northern Rapides Parish.

Figure A.3 and A.4 (in Appendix A) contains regional isopach maps of the [redacted] Group generated by CapturePoint Solutions. During Early [redacted], the [redacted] formation was deposited in a very broad syncline In Northwestern Vernon and Northeastern Rapides Parishes. The sands are believed to be dominantly delta channels, distributary mouth bars and strike oriented marine bar sands. The [redacted] Interval thickness within the Site's AoR is approximately 1,425 feet. Net Sand greater than 6 percent porosity within the [redacted] Sand interval is approximately 43 percent. Located around the [redacted] injection [redacted] in Figure A.3 is a 200 MM/D multisided polygon illustrating the size and location of a [redacted] million metric ton plume in 600' of [redacted] net sand. This is injection zone 2 with the plume located 6,188' from injection [redacted] 20 years after injection has ceased. [redacted] isopach, Injection Zone 3, illustrates a [redacted] depositional thick along the south flank of the AoR. Uplift on the Sabine Uplift was pronounced during [redacted] time as rapid thinning occurs along the northwest margin of the study area. The [redacted] Interval thickness within the site's AoR is approximately 2,400 feet. Net [redacted] Sand greater than 6 percent porosity is estimated at 700' or 29 percent of the [redacted] interval.

The [redacted] can be found at depths and thickness in the Gulf Coast province that will support regional CO_2 sequestration sites. These potential sites are estimated to have the storage capacity of greater than [redacted] tonnes annually. These clastic rich systems are generally found at depths conducive to CO_2 injection north of the Lower Cretaceous Shelf edge and within the margins of the interior salt basins (Carlson and Biersel, 2009).

2.1.2.3 Claiborne Group

The Claiborne Group in the Gulf Coastal Plain is widely thought of as a classic example of strata produced by alternating marine-nonmarine depositional cycles (Hosman, 1996). There are multiple sand and shale units that have been identified across the region that comprise the Claiborne Group. These are (in ascending order) the Cane River Formation, the Sparta Sand, the Cook Mountain Formation, and the Cockfield Formation.

Cane River Formation

The Cane River Formation represents the most extensive marine invasion during Claiborne time. In the central part of the Mississippi Embayment (Arkansas, Louisiana, and Mississippi), the formation is composed of marine clays and shales. It is glauconitic and calcareous in part, as well as, containing sandy clay, marl, and thin beds of fine sand. Well-developed sand bodies are found only around the margins of the Mississippi Embayment. Regionally, the sand percentage decreases markedly to the south and southwest, so that in southeastern Arkansas, southwestern Mississippi, and all of Louisiana, the Cane River Formation contains virtually no sand. Along the flanks of the Mississippi embayment and over the Wiggins Arch area the formation is generally 200 to 350 feet thick (Payne, 1972). It ranges from a thickness of 200 feet to 600 feet and deepens in bands towards the Gulf of Mexico. The Cane River is absent from the regional Sabine Uplift structure in the northwestern part of Louisiana (Figure 2-12) In the northern Louisiana region, the Cane River Formation acts as an additional regional confining unit, isolating the upper Sparta Aquifer from the deeper saline formations. Figure A.5 (in Appendix A) contains a regional isopach map of the Cane River Formation generated by CapturePoint Solutions. The Cane River averages 340 feet of shale. The Cane River isopach shows an interval thickness of approximately 400 feet within the AoR. The synclinal axis at deposition is a preferred north-south azimuth with the Sabine uplift strongly influencing depositional thickness during the Cane River shales' deposition.

Sparta Formation

The Sparta Formation is one of the Gulf Coastal Plain's most recognized geologic units. Overlying the Cane River Formation, the Sparta extends northward to the central part of the Mississippi Embayment deposited in a deltaic to shallow marine environment. The Sparta sand is composed of mostly very fine to medium unconsolidated quartz that is ferruginous in places to form limonitic orthoquartzite ledges. It is primarily beach and fluviatile sand with subordinate beds of sandy clay and clay. The Sparta ranges in thickness from less than 100 feet in outcrop (east and west) to more than 1,000 feet near the axis in the southern part of the Mississippi Embayment (Hosman, 1996, Figure 2-13). The Memphis sand is the equivalent formation in the northern part of Arkansas and southern Tennessee. Outcrops of the Sparta sands are in north central Louisiana along the edge of the Sabine Uplift. Note: that the Sparta is not deposited across this structural high. Figure A.6 (in Appendix A) contains a regional isopach map of the Sparta Formation generated by CapturePoint Solutions. The Sparta averages 550 feet of sand and shale within the northern Rapides' area of interest. In Central Louisiana, the Sparta sands are dominantly associated with the progradation of the ancestral Mississippi River's axis. This depositional axis is located approximately 50 miles east of the proposed Rapides sequestration site. The Sparta isopach map demonstrates the thickening of the unit to the east and the progradation of the Sparta delta North-northeast to South-southwest. The LaSalle Arch was not a dominate structural feature during the deposition of the Sparta formation. The percentage net sand greater than 6 percent porosity for the Sparta formation within the AoR is approximately 60 percent.

Cook Mountain Formation

The Cook Mountain Formation is predominantly a marine deposit that is present throughout the Gulf Coastal Plain. It is generally less than 200 feet thick in the Mississippi Embayment but thickens in Southern Louisiana and Texas to more than 900 feet (Figure 2-14). Along the central and Eastern Gulf Coastal Plain, the Cook Mountain Formation is composed of two lithologic units. The lower unit is glauconitic, calcareous, fossiliferous, sandy marl or limestone. The upper unit is sandy carbonaceous clay or shale which is locally glauconitic. The Cook Mountain Formation thickens downdip as the clay facies gradually becomes the predominant lithologic type. Figure A.7 (in Appendix A) contains a regional isopach map of the Cook Mountain Formation generated by CapturePoint Solutions. The Cook Mountain isopach shows an interval thickness of approximately 275' of thickness withing the AoR. Generally, the interval thins to the north and thickens to the south. [redacted]

Cockfield Formation

Lithologically similar to the Wilcox Group, the Cockfield Formation is present throughout most of the Gulf Coastal Plain, but less expansive in the interior than the other units in the Claiborne Group (Figure 2-15). Its Texas equivalent is the Yegua Formation. It is composed of discontinuous and lenticular beds of lignitic to carbonaceous coals and shale, fine to medium quartz sand, silt, and clay (Hosman, 1996). The Cockfield is generally sandier in the lower part. It is non-marine in origin and is the youngest continental deposit of the Eocene Series in the Gulf Coastal Plain. The Cockfield is thickest in the west-central part of Mississippi, with thicknesses ranging from 10 to 550 feet as it thins east and southeast (Figure 2-15).

2.1.2.4 Jackson Group

This Eocene-aged group extends from Texas to western Alabama in the Gulf Coast. The northern and southern terrigenous facies of the lower Jackson Group was formed as a destructional shelf facies by reworking of the upper surface of the Claiborne delta Systems (Dockery, 1977). In Louisiana, this was the deposits from the Mississippi Embayment. With the transgressive and regressive shoreline movement and the decrease in terrigenous clastic supply, offshore to nearshore environments formed. Deposition of carbonates alternating with mudstones and clays occurred. The Jackson Sea was the last maximum extent of sea level across the Mississippi Embayment. As a result, much of the Jackson Group sediments are of marine or near-shore origin.

The Moodys Branch Formation is the basal part of the Jackson Group and consists of fossiliferous, glauconitic sands, calcareous clays, and some limestones (Dockery, 1977). Multiple Eocene-aged fossils are specific to these deposition cycles are found within the Moodys Branch. Overlying these units is the Yazoo Clay Formation. The Yazoo Clay is primarily argillaceous, with thin sand lense members that are not regionally extensive. The clays have been described as fossiliferous and highly calcareous.

2.1.2.5 Vicksburg Group

The Vicksburg Formation lies within the Tertiary depositional wedge of the Texas Gulf Coastal Plain. Alluvial sands were funneled through broad valleys and grade seaward into deltaic sands and shales, and then into prodelta silts and clays. These sediments were deposited during periods of marine transgression, separated by thicker sections deposited during period of regression in the early Oligocene. The shoreline advanced and retreated in response to both changes in the rates of subsidence and sediment supply. Rapid down dip thickening occurs along the syn-depositional Vicksburg Flexure fault zone, where there may be as much as a ten-fold increase in formation thickness.

The contact between the Eocene-age Jackson Group and the Oligocene-aged Vicksburg group is almost indistinguishable in parts of the Gulf Coast. The lower part of the Vicksburg is marine and the lithology changes between the two groups is based upon paleontological breaks, which are not seen on logs. Therefore, the Jackson-Vicksburg Group is combined as a lager “megagroup” for discussion. The Jackson-Vicksburg is mapped across the Gulf Coast region (Figure 2-16) showing that the unit outcrops almost parallel with the current Gulf of Mexico coastline. The unit thickness in Louisiana ranges from 200 feet thick in the southeastern part of the state to 800 feet in the west. Figure A.8 (in Appendix A) contains a regional isopach map of Jackson-Vicksburg Shale generated by CapturePoint Solutions. The Jackson- Vicksburg isopach’s axis strikes north northeast and south southwest along the western flank of the Rapides sequestration site. Average thickness within the site is approximately 750 feet with a local depositional thick southwest of the site. The Sabine Arch/Uplift and LaSalle Arch were both positive features during the deposition of the Jackson-Vicksburg group.

2.1.2.6 Catahoula Formations

The Catahoula formation consists of lenticular beds of friable sandstone and siltstone and soft claystone. Two main units associated with the formation are the Frio Sandstone which is overlain by the Anahuac Shale. Deposition of the progradational Frio wedge was initiated by a major global fall in sea level, with subsequent Frio sediments being deposited under the influence of a slowly rising sea (Galloway et al., 1982b). The Frio Formation is composed of a series of deltaic and marginal- marine sandstones and shales that are the downdip equivalent of the continental Catahoula Formation (Galloway et al., 1982.) In southeast Texas and southwest Louisiana, a transgressive, deep-water shale and sandstone unit referred to as the “Hackberry” occurs in the middle part of the Frio Formation

(Bornhauser, 1960; Paine, 1968) In places, the Frio is regionally overlain by the Anahuac Formation, an onlapping, transgressive marine shale that occurs in the subsurface of Texas, Louisiana, and southwestern Mississippi (Galloway et al., 1982)

Updip to the Oligocene Frio Formation, the time-equivalent Catahoula Formation accumulated on the progradational continental platform inherited from Yegua, Jackson, and Vicksburg deposition (Galloway et al., 1982b). Sandstone composition in the Catahoula Formation reflects the nature of transport of volcanic debris and distance from the volcanic source. East Texas/West Louisiana samples have heavy mineral assemblages containing ultra-stable, polycyclic, metamorphic, and igneous minerals such as rounded zircon, sphene, tourmaline, staurolite, kyanite, apatite, rutile, sillimanite, and garnet (Ledger et al. 1984). South Texas samples contain abundant hornblende, zircon, apatite, and biotite (Ledger et al., 1984). The Trans-Pecos volcanic area is the probable source for the volcaniclastic material found in the Catahoula Formation (Ledger et al., 1984).

As sea level continued to rise during the late Oligocene, the underlying Frio progradational platform flooded. Wave reworking of sediment along the encroaching shoreline produced thick, time-transgressive blanket sands at the top of the Frio Formation and base of the Anahuac Formation (Marg-Frio) section. The transgressive Anahuac marine shale deposited conformably on top of the blanket sands throughout the Texas and Louisiana coastal region. The Anahuac shale was deposited in an open-shelf environment and is typically composed of calcareous, marine shales with localized, lenticular, micritic limestone units. The Anahuac Shale is regional, thickening from its inshore margin to nearly 2,000 feet offshore in the Gulf of Mexico (Galloway et al., 1982b).

2.1.2.7 Miocene-aged Formations

The Miocene strata of the Gulf Coastal Plain contain more transgressive-regressive cycles than any other epoch. Rainwater (1968) has interpreted the Middle Miocene as a major delta-forming interval comparable to the present-day Mississippi Delta system. The Miocene sediments of the Fleming Group of Louisiana are equivalent to the Oakville and Lagarto Formations of Texas, and to the Catahoula, Hattiesburg, and Pascagoula Formations of Mississippi. Members of the Fleming Group in central Louisiana, in ascending order are:

- Lena Member – Confining Unit
- Carnahan Bayou Member – Aquifer
- Dough Hills Member – Confining Unit
- Williamson Member – Aquifer
- Castor Creek Member – Confining Unit
- Blounts Creek (*not present at project site*)

Along the northeastern boundary of Texas, the Newton fluvial system supplied sediment to the Calcasieu delta system of Southeast Texas and Southwest Louisiana. Sands of the Newton fluvial system are fine to medium-grained, with thick, vertically, and laterally amalgamated sand lithosome geometries typical of meander belt fluvial systems (Galloway, 1985). Depositional patterns within the Oakville Formation (lower Fleming) of Southeast Texas show facies assemblages typical of a delta-fringing strand plain system (Galloway, 1985). The Calcasieu delta system is best developed in Southeast Texas in the Lagarto Formation of the upper Fleming. The delta system consists of stacked delta-front, coastal-barrier, and interbedded delta-destructional shoreline sandstones that compose the main body of the delta system, with interbedded prodelta mudstones and progradational sandy sequences deposited along the distal margin of the delta (Galloway, 1985).

The Middle Miocene represents much of the entire Miocene interval, with only the site of deposition changing in response to various transgressions and regressions. The result is a complex of interbedded shallow neritic clays; restricted marine clays, silts, and sands; and deltaic deposits of sands, silts, and clays. If a composite were made of the thickest Miocene intervals around the Gulf Basin, more than 40,000 feet of accumulated sediment would be obtained, of which about 20,000 feet were deposited in southern Louisiana (Rainwater, 1968).

Per Hosman, 1996, the complexity and heterogeneity of the myriad of facies making up Miocene strata, preclude development of continuous horizons and have frustrated attempts at regional differentiation. Much of the southern portion of Louisiana use terminology for the sands based upon their depth interval location at their sites (*i.e.* sand packages at 6,400 feet are termed "6,400-Foot Sand"). Therefore, the Fleming Formation may have differing terminology and be dependent on a more localized portion of the region. Figure 2-17 shows that the Miocene Formation exists in outcrop at or near the Rapides Parish location but extends to depths below 8,000 feet along the southeastern portion of Louisiana.

2.1.2.8 Pliocene-aged Formations

Pliocene age formations in Louisiana, although separated into upper and lower units, are mostly undifferentiated and unnamed. Much of the Pliocene and younger sediments were deposited offshore of the present coastline. Nearer shore, sediments were deposited under predominantly fluvial-deltaic conditions and exist as a complex of channel sands, splays, and overbank flood plain marsh deposits. Further south along the coast in southern Plaquemines Parish, the Pliocene section is approximately 6,000 feet thick (Everett et al., 1986). At the project site, the Pliocene-aged formations are not present. See Figure 2-18 for regional extent of the Pliocene Formation.

2.1.2.9 Pleistocene and Holocene Formations

Pleistocene sediments were deposited during a period of fluctuating sea level and represent a fluvial sequence of post-glacial erosion and deposition. The formations were deposited in both fluvial and deltaic environments and they thicken in a southeastward dip direction as well as southwest along strike toward the southwest. Pleistocene sediments thicken along the Texas-Louisiana border and in a dip direction where there was significant deposition along growth faults during Pleistocene sea level lowstands (Aronow and Wesselman, 1971). Thickest portions of the formation are along the and towards the Gulf of Mexico. These are relatively shallow (~2,000 feet deep) and up to 5,000 feet thick. Pleistocene sediments grade conformably into the overlying Holocene depositional units. At the project site, the Pleistocene-aged Formations are not present.

With the retreat of the Pleistocene glaciers, sea level began a final irregular rise to its present-day level. Holocene sediments were deposited following the final retreat of glacial ice. The slow rise of the Holocene sea level marked the beginning of the recent geologic processes that have created the present Texas and Louisiana coastal zone. During recent times, sediment compaction, slow basin subsidence, and minor glacial fluctuations have resulted in insignificant, relative sea level changes. The coastal zone in Louisiana has evolved to its present condition through the continuing processes of erosion, deposition, compaction, and periods of subsidence. The Holocene sediments in Rapides Parish site unconformably overlie the Miocene-aged Fleming Formation, representing a long period of time of non-deposition and erosion. The Holocene formations at the site are deposited in river valley meander belts and primarily composed of point bar sandstones, with interbedded finer-grained overbank deposits and alluvium, deposit (Figure 2-19).

2.1.3 Regional Structural Geology

Tectonism caused by sediment loading and gravity has played a major role in contemporaneous and post-depositional deformation of Tertiary strata, however the continental margins and deep ocean basin regions of the Gulf of Mexico, are relatively stable areas (Foote et al., 1984). During the Late Triassic to Early Jurassic, large volumes of eroded material were deposited on areas of regional subsidence. Isolated basins formed and where the Louann Salt formation was buried by a period of continuous clastic deposition. Northern Rapides Parish is located approximately 10 miles north of the Lower Cretaceous shelf edge. Major regional structures of interest are the North Louisiana Salt Basin, the LaSalle Arch, and the Sabine Uplift (Figure 2-20). The Sabine uplift (northwest of site) and the LaSalle Arch (northeast of site) are two regional uplifts that created a broad low relief syncline/embayment that was present at least through Oligocene time. During the first 35 million years of Cenozoic deposition, the northern Rapides area, and the Gulf Coast Region in general experienced 4 major eustatic events. These major high stands events are marked by the Midway Shale, Cane River Shale, Cook Mountain Shale and Jackson-Vicksburg Shale.

The Sabine Uplift located northwest of sequestration site is a large domal structural feature 90 miles long (NW-SE) and 60 miles wide (SW-NE) (Figure 2-4, and 2-20). The Sabine Arch or Uplift is a basement cored Jurassic horst that persisted throughout the Cretaceous Period as a topographic relict of tectonic rifting, (Adams, 2009). The Sabine Arch is a large positive feature at nearly 12,000 square miles and it separates the East Texas Basin from the North Louisiana Basins, (Adams, 2009). The Sabine uplift originated as a mid-rift high during the Triassic rifting period during the opening of the Gulf of Mexico. Sabine Arch was uplifted during middle to late Cretaceous and during Paleocene/Eocene time due to the Laramide foreland tectonics (Adams, 2009). Historically, the Sabine uplift area has been natural gas productive from Lower Cretaceous age reservoirs**.** A less dominate structural feature, the Angelina-Caldwell flexure is located west-southwest of the sequestration site. This flexure serves as the southern boundary to the East Texas Basin**.**

The LaSalle Arch divides the Mississippi and Lousiana Salt Basins. It is rooted within a basement high, a relict Paleozoic continental crustal block (Lawless & Hart, 1990). It is supported by basement paleo-highs with the eastern limb of the arch formed by regional tilting to the east and the western limb formed from differential subsidence to the southwest. (Lawless & Hart,1990). The southern most exent of this feature is approximately 30 miles northeast of the sequestiation site. The western limb developed syndepositionally due to differential subsidence, and the eastern limb developed due the relative regional tilting eastward after deposition of the Claiborne and Sparta formations (Lawless, 1990). The central and southern regions of the arch have been hydrocarbon productive, primarily from Wilcox sands.

The sequestration site is located between these remanant Paleozoic crustal blocks within a broad shallow syncline (Mississippi Embayment). The embayment was created from the regional structural uplift of the Sabine Arch and the LaSalle Arch. Near the proposed sequestration site's southern margin in Rapides Parish is the beginning of the Cretaceous shelf edge. The Cretaceous shelf edge is created by a steep structural dip change down into the Gulf of Mexico Basin. Lower Cretaceous Buda, Georgetown, Sligo and Mooringsport formations all have had localized vertical reef development all along this shelf edge. A large vertical Sligo-Mooringsport age reef is located along this shelf edge south of the proposed sequestration site. This geologic feature marks the northern rim of the Gulf Coast Geosyncline and is uniquely similar to the modern-day Great Barrier Reef complex in Australia.

Figure A.9 (in Appendix A) is a regional North-South Structural Cross Section A-A' that is approximately parallel to dip. The cross section illustrates the regional confining shales and the saline reservoir potential sands. The confining zones are brown, and the sands are in yellow. The cross section covers 26 miles across the AoR and the datum is mean sea level, MSL. Figure A.9 shows that the intervals are free of faults updip and downdip of the proposed injection site. Figure A.10 (in Appendix A) is a regional North-South Stratigraphic Cross Section A-A' hung on the top of the Vicksburg-Jackson Shale unit. This figure demonstrates the extensive lateral extent and consistent thickness of all the proposed confining and injection zones for the defined area north and south of the proposed injection site. Raster log images for cross sections A and B are found in Appendix C.

Figure A.11 (in Appendix A) is a regional West-East Structural Cross Section B-B' that is approximately parallel to strike. The cross section illustrates the regional confining shales and reservoir potential sands. The confining zones are brown, and the sands are in yellow. The cross section covers 39 miles across the AoR and the datum is MSL. Figure A.11 shows that the intervals are free of faults to the west and east of the proposed injection site. Figure A.12 (in Appendix A) is a regional East-West Stratigraphic Cross Section B-B' hung on the top of the Wilcox Big Shale unit. This figure demonstrates the extensive lateral extent and consistent thickness of all the proposed confining and injection zones for west and east of the proposed injection site.

Regional structure maps (Table 2-1) were developed by CapturePoint Solutions for analysis of structures and dips in the proposed confining and injection zones and are contained in Appendix A. The proposed upper confining zones of the [redacted] (Figure A.13) and the [redacted] (Figure A.14) show the general structural strike for these formations to be in an east-west orientation. Dip rates are less than two degrees south, and neither regional or local faulting is present. The lower confining structure map of the [redacted] (Figure A.15) shows an average of a 1.6-degree dip to the south. These upper and lower confining zones are free of faulting and generally thin over the large arches and uplifts located northeast and northwest of the proposed Rapides sequestration site. All confining zone isopach's illustrate the Rapides embayment and its subtle depositional thickness changes within the AoR. The extensive regional nature of these early to middle Cenozoic shales demonstrate that they are excellent regional seals.

Structure maps for the proposed injection zones of the [redacted] formations are contained in Figures A.16, A.17, and A.18; respectively. All injection zones dip to the south and are free from faulting or geological structures. Raster log images for cross sections A and B are found in Appendix C.

In addition, structure maps were generated for two internal containment zones. These zones, the [redacted] (Figure A.19) and the [redacted] (Figure A.20) are impermeable layers that separate and isolate the three injection zones. The [redacted] Formations overlies the top of the [redacted] Formation, creating a seal between the upper and middle injection zones thereby preventing vertical migration of injectate and creating pressure independence for each injection zone. [redacted] unit provides the same constraints for separating the [redacted] injection zones. All zones are reservoir modeled independently of one another.

2.1.4 Regional Groundwater Flow in the Injection Zone

The injection Zones for the CapturePoint Solutions Rapides site are identified as the [redacted] Formation (Injection Zone 1), the [redacted] (Injection Zone 2) and sands within the [redacted] (Injection Zones 3). The direction of downward vertical flow in Injection Zone 2, [redacted] is south and lateral flow is north and east. The direction of downward vertical flow in Injection Zone 3 is also downward with minimum lateral flow, (Williamson and Others, 1990)

The structural dip rate for the top of the [redacted] is 1.6 degress (Figure A.17). Within the injection zone sands, intervals of dip-oriented delta front sands and strike oriented bar sands will be the principal targeted sequestration intervals. All formations within the AoR have less than a two-degree structural dip rate.

Many of the studies for flow rates in deep saline aquifers come from the search for nuclear waste isolation sites. These studies show sluggish circulation to nearly static conditions in the deep subsurface (Bethke et al., 1988). Flow rates in the deep saline aquifers (Clark, 1988), were found generally to be on the order of inches per year. Site specific data on regional fluid flow in the injection zones will be collected via the injection wells and in-zone monitoring wells once completed.

2.2 Local Geology of the Rapides Parish Site

CapturePoint Solutions sequestration site is located within northwestern Rapides Parish. The site is located within [redacted] (Figure 2-21). The site is positioned at the [redacted] extent of the [redacted] near the [redacted] watersheds headwaters. A northwest-southeast surface ridge dissects the southwest flank of the AoR forcing drainage into the [redacted]. [redacted].

The [redacted] and proposed Rapides sequestration site is near the [redacted] of the state and is located approximately [redacted] of the of the city of [redacted], the [redacted] largest city in the state. A topographic map to scale 1:24,000 is provided as Figure 2-22. The general topograppphic relief is a dendritic ridge and valley features over an elevation of 250 feet to 150 feet above sea level. The area is heavily forested with manmade lakes common in and along the northern flank of the AoR. Figure 2-22 also illustrates where the private lands are located [redacted]. These privately owned tracts will serve as the locations for the injection wells, monitor wells and the proposed sequestration facilities. The principle advantage of locating operations on private lands is that it significantly reduces permitting requirements for the [redacted]. This figure also documents that the pore space, which is required by the sequestration site, [redacted] The proposed site's surface elevation is approximately 200' above sea level. [redacted] The three Wilcox dry hole's are located in [redacted] (Figure 2-22), all along the eastern third of the AoR.

Cross section C-C' is expressed across Figure 2-22. The cross section shows the six proposed injection wells completed into the injection zones (Figure 2-23) across the AoR. The cross section illustrates the six proposed injection wells within the sequestration site. They are the [redacted]. The plant boundry will be located in close proximity to the [redacted] monitor well #8.. The northern most well is the proposed Stratigraphic test well that will be used as a monitor for the [redacted] injection interval. The interval thickness of these formations are listed in the schematic. The Upper and Lower confining zones are the [redacted]; respective at a thickness of 280' and 850'. The [redacted], an internal containment zone, is also present. The [redacted] is a 340 foot thick confining zone that isolates the [redacted] injection interval (Injection Interval No. 2) from the [redacted] Injection interval (Injection Interval No. 1). Finally, [redacted], which is 750 feet thick, serves as a secondary or safety zone and is illustrated in red. The [redacted] acquifer monitor well #8 will monitor pressures to confirm the [redacted] is not breached or compromised over the life of the project. The proposed Stratigraphic test and later [redacted] monitor well #3 in [redacted] will monitor pressure and will also be logged for base line comparisons in order to monitor the CO_2 plumes growth during the late stages of project injection.

Figure 2-24 illustrates the relationship of the [redacted]. Approximately [redacted] residential structures are located within the AoR along with 110 registered active ground water wells [redacted] Also displayed are the proposed injection and monitor wells along with the three Wilcox dry holes that were drilled in the mid-1970's

The local geology section contains detailed maps and cross sections that are focused on the AoR. Table 2-2 contains the information on Maps and Cross Sections used in the local evaluation. All figures are contained in Appendix B – Local Maps and Cross Sections. All maps are constructed at a "1 inch to 2,000 feet" scale. These maps have been generated using Kingdom from IHS Markit.

The following sections detail the geology and data sets used on a locally affected scale, specific to the area at and around the proposed sequestration site.

2.2.1 Data Sets

Figure B.1 (in Appendix B) illustrates the 22 area wells that were correlated for the area's local structural style including 2-D seismic confirmation for the Rapides sequestration site. Porosity logs are limited in the area to one formation density-compensated neutron log and four various types of sonic logs. However, over 225 wells were evaluated for the area's regional structural and depositional style. Seven (7) lines of 2-D, green lines on Figure B.1, totaling 87 miles was purchased to collaborate the structural and depositional trends within the Cenozoic section in northwest Rapides Parish. Table 2-3 contains a tabulation of wells that are found within the AoR. Well logs were acquired from the LDNR Sonris Data base , IHS market database and other third party well log libraries.

The AoR had seven exploratory oil and gas wells drilled, all but one exploratory well was drilled through the [redacted] confining zone. Four of the seven dr yholes are located on the eastern flank of the [redacted] 1 AoR wells were drilled through the [redacted], the primary upper confining zone, and four of these wells were also drilled through the [redacted]. A public records request was sent to the Louisiana Department of Environmental Quality regarding occurrences of hazardous waste clean up sites or subsurface cleanup sites under CERCLA or RCRA. The results of the request sent on March 29, 2023 resulted in no findings of such occurrences within the AoR. Additionally there are no Class I injection wells, subsurface mines, or Tribal lands within the AoR. There are two abandoned sand and gravel quarries within the AoR. Detailed evaluation of the offset well construction are detailed within the AoR and CA report.

CapturePoint Solutions purchased licenses for seven 2-D seismic lines equaling nearly 88 miles of coverage from Seismic Exchange Incorporated, "SEI", Table 2-16. Most of the lines were originally shot in the 1980's using dynamite for a fold value between 24 and 45. Hardin International reprocessed all the licensed data for a Pre-Stack Time Migration processing sequence that included PSTM and Post Stack Enhancement. All lines were confirmed for phase and tied. Lines [redacted] were further processed for Acoustic Impedence Inversion. A synthetic using sonic and density data was generated from [redacted] that is located just outside the AoR along the northwest side. Lines were loaded into Kingdom, interpreted with the Hana synthetic and mapped to depth using the formation tops from wells drilled within the local area.

Figure (Appendix B-2) Line JMC-91 is a strike-oriented azimuth seismic line that is positioned over the AoR. This 2-D seismic panel illustrates and confirms no faults are located within the Jackson-Vicksburg to Top of Chalk horizons. In fact, no faults were observed in the AoR on any of the 2-D lines. The confining zones of [redacted] are identified. This seismic section over the AoR illustrates the “pancake” geology of the proposed sequestration site. This line and the north-south line along AoR’s western margin was processed with pre-stack amplitude preservation for Deterministic Post-stack Acoustic Impedence Inversion (AI). The acoustic impedence will be used quantitatively to map and model the reservoir sands within the three injection zones for increased modeling accuracy.

2.2.2 Local Stratigraphy

The injection and confinement system present beneath the Rapides site is composed of sediments that range in age from Paleocene to Miocene and then uncomfortably overlain by Holocene. The local stratigraphy is established on a type log (Figure 2-2) and used as a basis for correlating with the offset well data. Note: that this well is located within the southern portion of the AoR and was drilled to a total depth of 8,612 feet. It does not penetrate the lower confining zone which is projected to lie at depths greater than 9,000 feet.

Using this type log, the following local stratigraphic formations were evaluated:

- Midway Shale
- Wilcox Formation
- Claiborne Group
- Jackson Group
- Vicksburg Group
- Catahoula Formation
- Fleming Formation

In addition to the Type Log in Figure 2-2, the [redacted] well is used to provide details for the upper 95 feet of surface. This well is located approximately 5,400 feet northwest of the AoR circle. The [redacted] log documents the saline Catahoula Formation and the freshwater Fleming Formation, in addition to the possible Evangaline Formation of Pliocene age. Pleistocene terraces are also possible outcrops within the AoR. The [redacted] was also used for the sesimic synthetic and post stack inversion as it is the only well within the AoR with a sonic and density log.

Localized isopach maps were developed for the upper confining zones. These are Figures B.3 and B.4 in Appendix B. The Jackson-Vicksburg Shale is a regionally impressive transgressive "flooding/highstand' event with the interval obtaining an average thickness of 750 feet in the AoR. The primary confining zone is the [redacted], which located approximately 900 feet below the Jackson-Vicksburg Shale. Within the AoR, the [redacted] Shale averages 280 feet and thickens significantly to the southeast of AoR. The Lower Confining Zone – [redacted] isopach is presented in Figure B.5 (in Appendix B). This lower shale is 850 feet thick across the AoR.

Injection Zone 1 is the [redacted] is a series of sands with alternating shales (Figure B.6). Generally, the sands thin to the west at 540 feet of thickness and thicken to 640 feet in the east.

Injection Zones 2 consist of the [redacted] and Injection Zone 3 consist of the [redacted]. This formation is alternating sands and shales. The [redacted] averages 4,000 feet within the AoR. Figures B.7 and B.8.

Details on the formation characteristics are contained in Section 2.3.

2.2.3 Local Structure

There are no local structures within Northern Rapides Parish. Regional and local geology has demonstrated the subsurface geologic strata are on homoclinal dip at a dip rate of 1.5 to 2.0 degrees towards the south (See Appendix A and Appendix B for structure maps and cross sections).

Five geophysical enhanced structure maps were constructed to illustrate the local structure for the sequestration site. These maps are the top of the [redacted] (Secondary Confirming Zone) in Figure B-9, top of the [redacted] (Injection Zone No. 1) in Figure B-10, Top of [redacted] (Injection Zone 2) in Figure B-15, Top of [redacted] in Figure B-14, and the top of [redacted] in Figure B-11. All maps illustrate the shallow homoclinal dip of the AoR north of the Cretaceous shelf edge. These maps also indicate that the site and local geology is free of faults from the lower confining zone ([redacted]) through the secondary confining zone ([redacted]).

The proposed [redacted] injection intervals are not structurally or stratigraphically trapped. The proposed site is within a low relief regional syncline, locally defined as the Vernon-Rapides Parish embayment, located between the LaSalle Arch and the Sabine uplift. Structural dip rates of the confining zones and the injection intervals average approximately 1.5 degrees and no greater than two degrees. This minimal dip rate will contain the dense phase CO_2 plume after injection has ceased. The local geological structural fabric within the AoR is uncomplicated, and therefore does not have any uncertainties or alternative interpretations.

CapturePoint Solutions has defined the Area of Review "AoR" (the region encompassing the CO_2 storage site where particular attention must be paid to USDW protection) as the projected lateral and vertical migration of the CO_2 plume in each injection zone. Timeframe is from the start of injection until the lateral spread of the plume ends (approximately five years after injection stops).

The plumes are is modeled and detailed in the AoR and Corrective Action Plan Report [40 CFR 146.84(b)]. Modeling strategy and approach is based upon details of the confining and injection zone described in Section 2.3 of this narrative. To account for limited ground truth data, a stratigraphic test will be drilled in section 15 of 3N-3W and will assist in the modeling parameters analysis.

2.2.4 Faulting in the Area of Review

As evidenced by the structure and isopach maps prepared for the CapturePoint Solutions proposed site, there is no evidence of faults or subsurface structures within the projected AoR. Based upon all mapping performed and literature researched, the confining and injection zones within the AoR are all laterally continuous and free of transecting, transmissive faults or fractures which could cause movement of fluids into a USDW or freshwater aquifer.

2.3 Description of the Confining and Injection Zones

Demonstration of security for injection includes a geologic containment demonstration and the absence of vertically transmissive faults that could form breaches of the containment system.

The Confining Zone is defined as "a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement". For the CapturePoint Solutions site, this has been designated as the regionally extensive [redacted]. Above this formation lies the [redacted], which will act as a secondary upper confining unit, providing an additional measure of safety.

The injection zone is defined as "the geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project". Injection targets are identified as formations below a depth of 3,000 feet, which defines the top supercritical window for the injection of CO_2. Sandstones of the [redacted] between 4,649 feet and 5,179 feet and the sands of the [redacted] between 5,614 feet to greater than 9,000 feet contain the necessary characteristics to be an effective injection interval at this location (See Figure 2-2). The injection zones are located at least 2,500 feet below the lowermost aquifer that meets the criteria for being a USDW (less than 10,000 mg/l total dissolves solids content).

The geology characteristics for the CapturePoint Solutions site are summarized in Table 2-4, which is based upon offset analogue and regional core data. Site specific data will be collected during the drilling of the stratigraphic test well.

2.3.1 Confining Zones

Demonstration of security for injection includes a geologic containment demonstration and the absence of vertically transmissive faults that could form breaches of the containment system. In accordance with the EPA 40 CFR §148.21(b) standard, the confining zone is a laterally extensive and sufficiently low in permeability and porosity layer, which restricts the vertical flow of injectate. Within the CapturePoint Solutions study area, there are two identified upper confining zones (Figure 2-2); a primary and a secondary, separated by an intermediate buffer zone. The two Confining zones presented below both meet EPA and LDNR Standards and will restrict the vertical flow of injectate within the designated Injection Zone(s). Additionally, a lower confining zone has been identified underlying the lower most proposed Injection Zone. Depth and thickness of each zone have been based upon the offset log Baird BLM 26-5 No. 1 Well. There is no core data currently available for the confining zones in Rapides Parish. Data was acquired using literature sources, offset log analysis, and interval core data from within the state (where available in public domain).

NOTE: CapturePoint Solutions will collect additional site-specific data with downhole data acquisition during the drilling of the Injection and Stratigraphic Test wells. Details on the data acquisition are contained in Module D "*D Pre-Operational Testing Plan*" in this permit application.

2.3.1.1 Primary Upper Confining Zone – [redacted]

The primary upper Confining Zone is defined as corresponding to the shale-rich [redacted] Formation, which conformably overlies the injection zone. The [redacted] Formation is [redacted] in age and is comprised of alternating shale and calcareous facies. This unit extends from approximately 4,356 feet to 4,649 feet below ground (Figure 2-2). At the CapturePoint Solutions location, the [redacted] is expected to be approximately 280 feet thick with well data and seismic data supporting the area to be structurally free of transecting faults.

Along the Central and Eastern Gulf Coastal Plain, the [redacted] Formation is composed of two lithologic units. The lower unit is glauconitic, calcareous, fossiliferous, sandy marl or limestone. The upper unit is sandy carbonaceous clay or shale which is locally glauconitic. The [redacted] Formation thickens downdip as the clay facies gradually becomes the predominant lithologic type. Within the AoR there are no major facies changes. Facies changes occur updip (north of the regionally studied area for this report) towards north central Louisiana region.

2.3.1.1.1 Formation Characteristics

In lieu of direct core and limited literature data, porosities for the [redacted] Formation for the CapturePoint Solutions site were determined using correlations developed for Gulf Coast shales as presented in Porter and Newsom, 1987 (See Table 2-5).

The "effective" shale porosity, which discounts the bound water within the clay structure as well as water contained in dead-end pores, represents an appropriate choice of a porosity value for such a calculation. At the depths of interest, an effective clay/shale layer porosity of is based upon Table 2 in Porter and Newsom, 1987. Using this relationship for the minimum effective porosity in a shale versus depth, the maximum porosity in the primary Confining Zone at a depth of 4,000 feet is expected to be around 11 percent. Additionally, the permeabilities range are also derived from Porter and Newsom's Table 3 (See Table 2-6) and are expected to range between 1.9 x 10^{-3} and 2.3 x 10^{-3}mD.

Core data was not available for the [redacted] Formation. Analogues were taken from the [redacted] in Texas from the Shell Rock Catalogue (well location unknown) but with similar porosity and permeability as the shales present in the AoR, therefore a generic capillary pressure curve indicating high capillary entry pressures is taken as an initially representative analogue (Figure 2-25).

Site specific data on capillary pressures, permeability, and porosity will be collected and analyzed on core as it pertains to the outline in Module D "*Pre-Operational Testing Plan*".

2.3.1.1.2 Mineralogy and Petrophysics

Core data or images are not available for the [redacted] in the AoR; however, a general description was obtained from Jones (1969) in Louisiana indicating an abundant presence of siderite and siderite cements in the sandstone and mudstone units. The lower part is glauconitic, calcareous, fossiliferous, sandy marl or limestone, and the upper portion is sandy carbonaceous clay or shale, which is also likely glauconitic (Hosman, 1996). Glauconite is an iron potassium phyllosilicate mineral that forms through modification of clays and saltwater. Initial studies by Nguyen (2018) have tested reactions of supercritical CO_2 reactions with Glauconite which showed little to no carbonate principate formation between the two components. The [redacted] Formation integrity therefore will not be impacted by sequestration of CO_2.

The general description is consistent with low porosity and permeability sandstones and mudstones dominated by clay matrix (Hackley, 2012). Plans to characterize this unit further are included in Module D "*Pre-Operational Testing Plan*".

2.3.1.1.3 Buffer Zone – [redacted]

Additional overlying containment is provided by the saline aquifer sands of the [redacted]. It is composed of discontinuous and lenticular beds of lignite to carbonaceous shales, fine to medium quartz sand, silt, and clay. The [redacted] is generally sandier in the lower part. It is non-marine in origin and is the youngest continental deposit of the [redacted] Series in the Gulf Coastal Plain. The [redacted] is thickest in the west-central part of Mississippi, with thicknesses ranging from 10 to 550 feet as it thins east and southeast and is regionally extensive.

The sands of the [redacted] Formation will act as a "buffer zone" between the primary and secondary confining zones, which will then provide an additional margin of safety for containment of sequestered carbon dioxide. This saline aquifer sand formation above the Primary Confining Zone has porosity permeability development, based upon offset logs, to act as an additional barrier of containment and pressure bleed off zone. The area continuity of this buffer zone is sufficient to provide added protection to the USDW in the event of fluid movement in an unlocated borehole.

2.3.1.2 Secondary Upper Confining Zone – [redacted]

The secondary confining zone is located within the [redacted] Formation and consists predominantly of impermeable shale. The complexity of the lithofacies changes in this region has caused problems in establishing geologic ages and correlating formations. Sediments of the [redacted] were deposited in marginal marine environments, with clastic sediments grading into carbonate sediments across the basin. The terrigenous clastic deposits were sourced from older coastal plain sediments and Appalachian terrains.

The [redacted] lies approximately 900 feet above the [redacted] (Primary Confining Zone). An average of 750 feet of shale-rich strata accumulated at the CapturePoint Solutions site, providing a thick, robust secondary seal to the proposed Injection Zones. This formation extends from 2,665 feet to 3,423 feet below ground within the CapturePoint Solutions site (See Figure 2-2). Significant vertical separation of at least 2,000 feet exists between the top of the Secondary Confining Zone and the deepest USDW. There are no structural traps or faults though this Formation within the AoR and this secondary confining zone will maintain its seal integrity during injection operations.

2.3.1.2.1 Formation Characteristics

In order to characterize the porosity and permeability of the [redacted] at the scale of the entire U.S. Gulf Coast, petroleum-reservoir-averaged porosity measurements were plotted against reservoir depth for Paleogene sandstone reservoirs on the Gulf of Mexico coastal plain (Nehring Associates, Inc., 2010). Nehring Associates plotted 1,358 measurements and determined an average porosity of range of 22 (±4) percent.

For a comparison, the porosities for the [redacted] for the CapturePoint Solutions site were also determined using correlations developed for Gulf Coast (See Table 2-5). At the depths of interest, an effective clay/shale layer porosity of is based upon Table 2. Using this relationship for the minimum effective porosity in a shale versus depth, the maximum porosity in the secondary Confining Zone at a depth of 2,500 feet is expected to be between 12.5 and 13.5 percent. Additionally, the effective permeabilities ranges for Porter and Newsom (1987) (See Table 2-6) and are expected to range between 5.5×10^{-3} and 8.5×10^{-3} mD.
Capillary Pressure core data was not available for the confining zones. Analogues were taken from the [redacted] formation in Texas from the Shell Rock Catalogue (well location unknown) but with similar porosity and permeability as the shales present in the AoR, therefore a generic capillary pressure curve indicating high capillary entry pressures is taken as an initially representative analogue (See Figure 2-25).

Site specific data on capillary pressures, permeability, and porosity will be collected and analyzed on core as it pertains to the outline in in Module D "*Pre-Operational Testing Plan*".

2.3.1.2.2 Mineralogy and Petrophysics

The [redacted] contains glauconitic sand and sandy marl at its base. The [redacted] (in the lower [redacted]) grades upwards into grey to yellow calcareous ductile clay. The upper portion of the group becomes more fossiliferous and argillaceous. The clay is predominately dark grey to blue and may be calcareous to varying degrees (Hosman, 1996). Hosman also notes that the formation increases in calcareous natures in the eastern part of the Gulf Coast with an increase in marls and limestones as the dominant lithologies.

The [redacted] grades into the [redacted]. Lithology of the [redacted] varies from arenaceous and argillaceous to marl and limestone (Hosman, 1996). The [redacted] and clays have been described as containing fossils (mostly shells) and glauconite. Limestones in the group have been described as hard and ferruginous coloured from blue (fresh) to yellow (weathered). A [redacted] analogue sample found in Texas shows a very fine-grained argillaceous sandstone with pore filling clays and calcite cements (Figure 2-26). Secondary porosity and permeability ranges are expected to be in the nano to micro-Darcy range.

2.3.1.3 Lower Confining Zone – [redacted]

Shales of the [redacted] form the lower confining zone beneath the proposed Injection Zone 2 ([redacted]). The [redacted] is a thick calcareous to non-calcareous clay, locally containing minor amounts of sand. The top of the formation is approximately 9,500 feet below ground. The upper contact with the overlying [redacted] is gradational. Wood and Guervara (1981) defined the top of the [redacted] as the base of the last [redacted] greater than 10 feet thick. The [redacted] is projected to be at a minimum of 750 feet of impermeable marine shale referenced to the [redacted]. The precise thickness of the Midway is difficult to measure because it often cannot be differentiated from the underlying upper [redacted] (Upper Cretaceous) using electric logs but overlies the [redacted]. The [redacted] are generally grouped together during electric log correlations.

In light of its thickness and lateral continuity along both strike and dip, there is no doubt that the lower confining unit is an effective seal for injection into the overlying Wilcox sandstones in the area around the proposed injection site, The Midway Group is regional in extent, thickening from the East Texas Basin, towards the Gulf of Mexico.

2.3.1.4.1 Formation Characteristics

There is limited permeability and porosity data on the [redacted]. However, whole core from the lower portion of the [redacted] was taken by DuPont in 1993 during the drilling of their Class I Injection [redacted]. This core is representative of assumed data at the proposed site. Eighteen plugs were analyzed for porosity and permeability. The results described an average porosity of 16 percent, and air permeability is 2.4 x 10^{-3} mD (See Table 2-7). These test results of extremely low permeability demonstrate the excellent confining capabilities of the [redacted]. At the [redacted], the [redacted] is used as the upper Confining Zone and historical and current operations show that this geological unit contains suitable characteristics for confinement.

2.3.1.4.2 Mineralogy and Petrophysics

Table 2-7 also contains a summary of the mineralogic data derived from a whole core sampled from the [redacted] core analysis in the [redacted]. An x-ray diffraction analysis indicated that the samples consisted mostly mainly of clay and quartz. Dominant mineralogy was illite/smectite with calcite and quartz. Minor components of Plagioclase and Potassium Feldspars.

The predominant lithology is a dark gray to black, fissile, carbonaceous, and pyritic shale. Occasionally included thin fine laminae of fine to very fine, moderately sorted micaceous and carbonaceous sands.

Overall, the 1,200 feet of cored [redacted] was described as fairly uniform throughout, with swelling Illite dominated clays. The Formation has little to no sands, which bolster low to impermeable modeled characteristics.

The ternary diagram from the XRD data shows two main rock types from the sampled material (Figure 2-27) with main mineralogy alternating between carbonate and quartz bed but both having 50 to 100 percent pore filling clay content. The available [redacted] core porosity permeability data shows a consistent trend with increasing permeability as core porosity increases, indicating possible grain size and associated sorting controls in permeability (Figure 2-28). These correspond with pore throat size distribution and expected capillary pressures.

Plans to characterize the [redacted] for the site are shared in Module D "*Pre-Operational Testing Plan*".

2.3.2 Injection Zones

The injection zone is defined as "the geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a GS project". [redacted] contain the necessary characteristics to be an effective injection interval at that the CapturePoint Solutions site. The injection zones have been designated as follows:

[redacted]

The [redacted] formation is a regionally extensive geological shale unit that underlies the [redacted] Formation and acts as a barrier between the Injection Zones 1 and 2. The [redacted] is subdivided into two independent injection zones due to the subregional shale unit known as the [redacted], which is modeled as a containment unit. All characteristics for the units are discussed in the following sections.

Like the Confining Zones, there is limited core data currently available for the injection zones near Rapides Parish. Data was acquired using literature sources, offset log analysis, and interval core data from within the [redacted] located approximately [redacted] miles to the west-northwest of the proposed site (Figure 2-29).

2.3.2.1 Injection Zone 1 – [redacted]

The [redacted] is composed of mostly very fine to medium unconsolidated quartz that is ferruginous in places to form limonitic orthoquartzite ledges. It is primarily beach and fluviatile sand with subordinate beds of sandy clay and clay. The [redacted] ranges in thickness from less than 100 feet and outcrop to more than 1,000 feet near the axis in the southern part of the Mississippi Embayment (Dixon, 1963). At the proposed site, the sands thicken to the east (Figure B.6, Local Sparta Isopach Map has a maximum thickness for the [redacted] within the AoR of 640 feet).

2.3.2.1.1 Formation Characteristics

The lithology of the [redacted] is highly variable both vertically and laterally (Payne, 1968). As a result, the permeability of the sand can also vary. In the channel sand facies, the permeability increases with the sand-unit thickness. Payne, 1968 concluded that movement of groundwater in the [redacted] is higher along continuous thick channels, as opposed to the inter-channel areas.

In Hackley 2012, the porosity of the [redacted] in central Louisiana is reported as ranging from 21 to 34 percent and permeability ranging from 60 md to greater than 1,000 md. In Pointe Coupee Parish (southeast of the project site), the [redacted] lie at much deeper depths of approximately 11,500 feet. Krutak and Kimball (1991) presented studies from cores in Fordoche Field indicating an average porosity of 24.7 percent and a permeability ranging from 200 to 300 mD for the [redacted]. Additional literature sources show an average porosity of ranges from 20 to 35 percent, and average permeability ranges of 0.1 to greater than 1,000 mD (Pierson, 1970, Nehring, 1991; Nehring Associates, Inc., 2010).

The available literature data sources are all consistent in the ranges for porosity and indicate that the permeability varies with locality and deposition. It is therefore assumed that thicker channel sands will have higher permeability coefficients. Averages of 20 to 25 percent porosity and 200 to 500 mD are assumed for the CapturePoint Solutions site.

Capillary pressure data was not available for the [redacted]. Analogue data is limited to the [redacted] (Injection Zone 2 and Injection Zone 3), which was obtained from offset oil and gas wells. Site specific information will be collected and tested for capillary pressures within the [redacted], as outlined in Module D "*Pre-Operational Testing Plan*".

2.3.2.1.2 Mineralogy and Petrophysics

The [redacted] is composed mostly of very fine to medium unconsolidated quartz sand that is sufficiently ferruginous in places to form limonitic ortho-quartzite ledges, generally in the lower part of the unit (Hosman, 1996). Like the overlying [redacted], the [redacted] also contains the mineral glauconite. Other minerals are lignite and organics, but the [redacted] lacks an overall abundance of fossils. Detrital glauconite is abundant; detrital cheer is less common, potassium feldspars and sodic plagioclases are rare (Krutak and Kimbrell, 1991). It also may contain calcite as a secondary mineral. The [redacted] has been described as containing laminae and crossbreds.

Regional analogue for the [redacted] indicates high porosity and high permeability samples with pore throats ranging from 10-20 microns as estimated from SEM images, which is consistent with the previous field studies in the prior section (Figure 2-30). Additionally, cores from the [redacted] in the [redacted] in Point Coupee Parish indicated pore throats averaging approximately 10 microns. Note, that the samples from this field come from much deeper depths at 11,300 feet. Cements such as chlorite, quartz, calcite, and other carbonate minerals are present in the formation which may reduce porosity and permeability. Krutak and Kimbrell (1991) also noted the existence of diagenetic clays such a chlorite and kaolinite and calcites with the [redacted] in the [redacted]. Kaolinite is described in that report as loosely attached to the host grains. The loose clays may potentially migrate through the formation and could potentially cause reduced porosity.

2.3.2.1.3 Expected Zone Capacity

The [redacted] Isopach and Structure maps of injection zone 1 (Figures B-6 and B-10) contains the CO_2 plume extent (a 7,128 feet radius wavy outline of blue colour) representing a total of [redacted] metric tons "Mmt" injected yearly for 20 years with the plume's extent drawn at the end of a 60-year period. The three modeled injection layers are each 100-foot thick with 30 percent porosity and 100 md permeability (absolute). Each 100-foot-thick layer is separated by a 10-foot tight layer modeled as impermeable zones. Vertical permeability is 10 percent of horizontal permeability across all layers. [redacted] structural dip rate is 1.44 degrees. Details are contained in the *Area of Review and Corrective Action Report* [40 CFR 146.84(b)] submitted in Module B with this permit application. The [redacted] is laterally extensive and free of structural traps and vertically transmissive faults within the AoR.

2.3.2.2 Containment Zone – [redacted]

The [redacted] Formation represents the most extensive marine invasion during [redacted]. In the central part of the Mississippi Embayment (Arkansas, Louisiana, and Mississippi), the formation is composed of marine clays and shales. It is glauconitic and calcareous in part, as well as, containing sandy clay, marl, and thin beds of fine sand. Well-developed sand bodies are found only around the margins of the Mississippi Embayment. Regionally, the sand percentage decreases markedly to the south and southwest, so that in southeastern Arkansas, southwestern Mississippi, and all of Louisiana, the [redacted] contains virtually no sand. Along the flanks of the Mississippi Embayment and over the Wiggins Arch area the formation is generally 200 to 350 feet thick. (Payne, 1972). In the northern Louisiana region, the [redacted] acts as a lower confining unit beneath the [redacted].

2.3.2.3 Injection Zone 2 – [redacted]

The upper [redacted] is generally considered to be transgressive with locally regressive wave-dominated delta lobes deposited during a global rise in sea level. An increase in the carbonate content and glauconite content in upper [redacted] sediments suggests an increase in marine conditions compared to [redacted]. An examination of [redacted] hydrocarbon producing trends in Louisiana and Mississippi concluded that the [redacted] is a transgressive sequence. Additionally, the [redacted] is represented by hyposaline to normal marine lagoonal sequences in which beds of lignite are unusual (Glawe and Bell, 2014). Figure B-15 is the seismically controlled structure map for [redacted], contoured on top of the [redacted].

In Rapides Parish, to the northeast of the site, core data and additional logs for analysis were available for the [redacted] from the [redacted] (Figure 2-31). This field is located approximately [redacted] miles west-northwest of the proposed site.

2.3.2.3.1 Formation Characteristics

The [redacted] provides the closest available data for the porosity and permeability of the [redacted]. Core data from four offset wells located in this field were used for an analysis on the permeability and porosity characteristics, as well as data from one nearby well. Table 2-8 contains the wells used in the analysis of the [redacted]. The nearest well to the site is the [redacted] (red dot location on Figure 2-31), located approximately [redacted] miles northwest from the Rapides Parish site. This well was used as the baseline and main trendline for the site.

Figure 2-32 contains a graph plot of the available core data. Note that the [redacted] (pink diamonds) corresponds with the regional trend for the [redacted]. The permeability data ranges from 1.7 mD (extreme low end) to 4,850 mD (extreme high end). The porosities range from 14.1 percent (low end) to 41.1 percent (high end). The high range in values is attributed to the variations in facies changes further updip and the extreme end members were not used in the average values. For the [redacted], average porosities values of 18 to 30 percent and average permeability values of 20 to 500 mD are estimated for this injection interval (Table 2-4). Detailed core analysis and facies studies will be conducted as part of the core analysis program contained in Module D "*Pre-Operational Testing Plan*".

Capillary pressure data in the [redacted] was obtained from regional oil and gas wells located in the [redacted]. Integration of petrographic, porosity and permeability, and mercury injection capillary pressure analyses was integrated to determine property controls. Publications indicate that pore networks in the [redacted] are subject to change with an increase in temperature during burial, changing from primary interparticle dominated (lower temperatures) to micropore dominated (higher temperatures) resulting in changes in the pore throat size distribution and capillary pressures (Figure 2-33).

2.3.2.3.2 Mineralogy and Petrophysics

A [redacted] regional study ternary diagram published by the Texas Bureau of Economic Geology (BEG) shows [redacted] XRD results from different locations along the Gulf Coast. The results show these sands within the feldspathic litharenites classification. Pore types are largely primary intergranular, with microporosity from secondary dissolution of lithic fragments. Quartz overgrowth is identified but limited. Mechanical compaction and quartz cementation were the most important porosity-reducing diagenetic events identified by Dutton and Loucks, 2014. Please note that this applies to both Injection Zone 2 – [redacted] and Injection Zone 3 – [redacted].

The [redacted] is composed of abundant amounts of quartz, mica, and carbonaceous material as have been described by Glawe and Bell, 2014. Additionally, traces of glauconite and pyrite have been identified as minerals with the uppermost [redacted]. Lowery (1988) also described the varying facies associated with the [redacted] as contained extensive burrows, shell debris and bioturbated sandstones along the stable shelf margin. Much of the facies are missing internal physical structures, such as cross-beds. Glawe and Bells (2014) also described thin carbonate rich beds in a core sample that were either calcareous fossils, limestone concretions, or calcite cements. Land and Fisher (1987) determined that carbonate cement was the dominant cement in the shallower onshore [redacted].

2.3.1.2.3 Expected Zone Capacity

The [redacted] Formation is expected to contain [redacted] percent volume of CO_2 injection. This is based upon the parameters of injecting [redacted] for 20 years. The formation dip is 1.44 degrees. The modeled five [redacted] injection layers approximately 200 feet thick with 100 md of permeability (absolute). Each layer modeled with 10 feet of impermeable strata. Details are contained in the Area of Review and Corrective Action Report [40 CFR 146.84(b)] submitted with this permit application. The [redacted] is laterally extensive and free of structural traps and vertically transmissive faults within the AoR.

2.3.2.4 Containment Zone – [redacted]

The [redacted] formations are not in hydrogeologic or pressure communication. An internal subregional geologic unit (a baffle) defined as the [redacted] represents major marine transgressive event and facies shift from fluvial-deltaic systems to deeper marine systems. It is a containment unit that caps and traps the production from the [redacted] Formation within Rapides Parish. It is greater than 80 feet thick within the sequestration site and free of vertically transecting faults and fractures.

2.3.2.5 Injection Zone 3 – [redacted]

The [redacted] is divided into the [redacted] parts dependent on to recognized major progradational cycles. Marine clays of the underlying [redacted] grade upward into the fluvial and deltaic sediments of the [redacted], which is composed of interbedded lenticular sand, mud, and lignite (Fogg and Kreitler, 1982). The [redacted] contains fluvial and deltaic channel-fill sand bodies distributed complexly in a matrix of lower permeability inter channel sands, silts, clays, and lignite's. Most of the sands are distributed in a dendritic pattern, indicating a predominately fluvial depositional environment (Fogg et al., 1983). The top of the [redacted] is marked by regionally transgressive shale, historically called the [redacted] in Louisiana and Mississippi (Rainwater, 1964a; Galloway, 1968). Production in the region is from the [redacted] in the [redacted] and the [redacted] in Rapides Parish. Unlike the [redacted], beds of lignite are found throughout the region in the lower portion of the formation.

Many publications and studies group and identify the [redacted] offshore as separate intervals, however for this project they are grouped as one unit as both distinctions are stratigraphically below the [redacted]. For the Rapides Parish the term [redacted] (onshore) is used to identify the sands below the containment unit (baffle) as Injection Zone 3 as they as exhibit similar characteristics and deposition histories. Figure B-14 is the seismically controlled structure map for [redacted], contoured on the base of the [redacted].

2.3.2.5.1 Formation Characteristics

The [redacted] consists of four major depositional systems (Galloway, 1968) from the base of the [redacted] to the top of the [redacted]. These are the [redacted] (delta system), [redacted] (lagoon system), a restricted shelf system, and a fluvial system (unnamed). Sands in the [redacted] are of bay fill deposits and distributary channels from a deltaic system.

Sands within the [redacted] have been identified with caps of lignite. It is estimated that these lignites may reach as much as 10 feet in thickness (Goddard et al., 1992). These lignite beds are then, in turn, overlain by transgressive shale units. The cyclic repetition of lignites is characteristic of the [redacted] and is the result of relative sea level fluctuations caused by rates of subsidence, types of depositional facies, quantity of sediment supplied to the area, and global influences (Goddard et al., 1992). Their research indicated that the thickest lignite seams are located at the transgressive and regressive maxima of the eustatic curves.

Individual intervals within the [redacted] will vary in porosity and permeabilities. Studies to the northeast of the proposed injection site (from Wildville field at the eastern edge of Louisiana) looked at specifically at a deltaic stack of sands. Permeabilities ranged from 91 to 524 md and averaged 280 md (Goddard, 2007). The same study showed the channel porosities average of 30 percent, with a range of 24 to 34 percent.

Like the [redacted], the [redacted] provides the closest available data for the porosity and permeability of the [redacted]. Core data from seven offset wells located in this field were used for an analysis on the permeability and porosity characteristics, as well as data from one nearby well for comparison. Table 2-9 contains the wells used in the analysis of the [redacted]. The nearest well to the site is the [redacted], located approximately [redacted] miles northwest of the Rapides Parish site. Figure 2-34 contains a graph plot of the available core data.

Note that the [redacted] (red circles) plots well with the regional trend from the [redacted], however slightly lower for both parameters. The available data for the [redacted] is less scattered than the [redacted] in comparison. The permeability data ranges from 1.4 mD (extreme low end) to 1,330 mD (extreme high end). The porosities range is from 17.3 percent (low end) to 38.6 percent (high end). The high range in values is attributed to the variations in facies changes further updip and the extreme end members were not used in the average values. For the [redacted], average porosities values of 10 to 30 percent and average permeability values of 50 to 400 mD are estimated for this injection interval (Table 2-4). Detailed core analysis and facies studies will be conducted as part of the Core Analysis Program contained in Module D "*Pre-Operational Testing Plan*".

Capillary pressure data in the [redacted] was obtained from regional oil and gas wells located in the [redacted]. Integration of petrographic, porosity and permeability, and mercury injection capillary pressure analyses was integrated to determine property controls. Publications indicate that pore networks in the [redacted] sandstones are subject to change with an increase in temperature during burial, changing from primary interparticle dominated (lower temperatures) to micropore dominated (higher temperatures) resulting in changes in the pore throat size distribution and capillary pressures (Figure 2-33).

2.3.2.5.2 Mineralogy and Petrophysics

Microporosity generated from dissolution with increased burial depth reduce permeabilities in the [redacted] (Dutton and Loucks, 2014). Moderately sorted to very well sorted grains with grain sizes ranging from very fine to fine sand, with the [redacted] sands tending to be slightly coarser than the [redacted] (Figure 2-35).

Lignites were deposited within a lower delta plain environment that had subsided and then compacted. Goddard et al 1992 presented a rock-eval pyrolysis showing oxygen indices of 11-62 and hydrogen indices of 145-321. There conclusions indicated that the organic material peat that developed into unmature lignite as result of consistent compaction.

A [redacted] regional study ternary diagram published by the BEG shows [redacted] XRD results from different locations along the Gulf Coast (Figure 2-36). The results show these sands within the feldspathic litharenites classification. Pore types are largely primary intergranular, with microporosity from secondary dissolution of lithic fragments. Quartz overgrowth is identified but limited. Mechanical compaction and quartz cementation were the most important porosity-reducing diagenetic events identified by Dutton and Loucks, 2014 (Figure 2-37). Please note that this applies to both Injection Zone 1 (B) – [redacted] and Injection Zone 2 – [redacted]. Land and Fisher (1987) determined that the dominant cement in the [redacted] is ankerite. They also noted that feldspar had undergone dissolution to Albite in the deepest portions of this unit and may play a role in secondary porosity.

2.3.2.5.3 Expected Zone Capacity

The [redacted] Formation is expected to contain [redacted] percent volume of CO_2 injection. This is based upon the parameters of injecting [redacted] annually for 20 years. The formation dip is 1.44 degrees. Five modeled injection layers at approximately 200 feet thick with 100 md of permeability (absolute). Each layer is separated by 10 feet of impermeable strata. Details are contained in the Area of Review and Corrective Action Report [40 CFR 146.84(b)] submitted in Module B with this permit application. The [redacted] is laterally extensive and free of structural traps and vertically transmissive faults within the AoR.

2.4 Hydrogeology

The primary regulatory focus of the USEPA injection well program is protection of human health and the environment, including protection of potential underground sources of drinking water (USDWs). The Underground Source of Drinking Water (USDW) is defined by the EPA as an aquifer which supplies any public water system and contains fewer than 10,000 mg/l total dissolved solids (TDS). The following sections detail the regional and local hydrogeology and hydrostratigraphy. [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

2.4.1 Regional Hydrogeology

The Water Resource Commission and the Water Management Advisory Task Force advise and promote policy concerning the states surface and subsurface freshwater aquifers. In August of 2019, the Council on Watershed Management agreed to use eight watershed regions as a starting point to coordinate efforts among parishes and distribute project funds. The Rapides Parish AoR is located primarily in Region 1. The eight watershed regions are illustrated in Figure 2-38.

The regional aquifers of Louisiana are contained on Figure 2-39 are contained within Paleocene and younger formations and which contain usable quality water (<3,000 milligrams per liter (mg/L) TDS). These aquifer systems regionally crop out in bands parallel to Mississippi Embayment and dip and thicken towards the southeast. Major aquifer systems that comprised the regional groundwater systems that are discussed are:

- the Carrizo-Wilcox aquifer
- the Sparta aquifer
- the Cockfield aquifer
- Catahoula aquifer
- the Jasper aquifer
- the Evangeline aquifer
- the Chicot aquifer
- and the Red River Alluvial System.

Figure 2-40 contains a hydrostratigraphic columns for the state of Louisiana. This column denotes the aquifer units for the regions of the State. Not all aquifers are present throughout. The deeper Eocene-aged aquifers of the Cockfield, Sparta, and the Carrizo -Wilcox aquifers, are only freshwater in the northern part of the state. In the Central and Southern part of the State, these same aquifers are saline as a result of dip and depth increases towards the Gulf of Mexico.

Freshwater aquifers such as the Evangeline maybe freshwater aquifers in the southern part of the states but are also considered saline near the coast due to salt-water intrusion. So, the geological location, as well as depth, of the hydrostratigraphic unit is important. A published regional stratigraphic section (D-D') parallel to dip from Smoot (1989) depicting the aquifers across Louisiana is contained in Figure 2-41. The following sections detail the regional hydrostratigraphic sections and their regional importance.

Groundwater moves through aquifer systems from areas of high hydraulic head to areas of lower hydraulic head. Regional uses from industry and the public water systems have some impacts on diverting the direction of flow. Where available, publish potentiometric maps for the regional aquifers are provided and discussed in their hydrostratigraphic section.

The following subsections detail the hydrostratigraphy for the Louisiana region.

2.4.1.1 Carrizo-Wilcox Aquifer

The Carrizo-Wilcox saline aquifer is confined by the 800 feet thick Midway Shale at its base. The Cane River Shale serves as the top confining zone at 350 feet thick. This aquifer becomes a source for freshwater in the northern portion of Natchitoches Parish, approximately 40 miles northwest of Rapides sequestration site.

The Carrizo-Wilcox aquifer system consists of the Carrizo Sand of the Eocene Claiborne group and the undifferentiated Wilcox group of Eocene and Paleocene age. They are hydrologically connected and act as one hydrogeologic unit. The Wilcox deposits, outcropping in northwestern Louisiana, are the oldest deposits in the state containing fresh water that are used for public supply and are the surficial recharge points for the aquifer. The aquifer operates under confined conditions, except in the outcrop areas.

In 2010, about 19 million of gallons per day (Mgal/d) were withdrawn from the Carrizo-Wilcox aquifer in Louisiana (Fendick and Carter, 2015). Groundwater flow is generally towards the Red River Valley. However, potentiometric maps (Figure 2-42) show that that the regional flow is altered near in this system is towards populated towns of Mansfield, Keithville, and Castor due to their heavy withdrawal from the system. In the Rapides Parish sequestration site area, this system is saline. Details on the Geochemistry is contained in Section 2.7.

2.4.1.2 Cane River Formation - Aquiclude

The Cane River is a regionally extensive low-permeable layer composed of primarily clay that overlies the Carrizo-Wilcox Formation, except in northwestern Louisiana where the aquifer outcrops.

2.4.1.3 Sparta Aquifer

The Sparta Aquifer extends from northeast Texas to central Mississippi. It is a major source of freshwater in the north-central part of Louisiana and Arkansas. The Sparta aquifer is recharged through direct infiltration of precipitation, the movement of water through overlying terrace and alluvial deposits, and leakage from the Cockfield and Carrizo-Wilcox aquifers. The base of the unit is medium to fine grained sand that grades upwards into clay. The Sparta sand ranges in thickness from 500 to 900 feet in the areas it contains freshwater (Rollo, 1960). The Sparta sand thins over the LaSalle Arch and Monroe Uplift.

The regional flow direction for the Sparta Aquifer is eastward, towards the axis of the Mississippi Embayment. The Sparta is an artesian aquifer system, which is confined by the lower permeable strata of the Cook Mountain Formation (overlying) and the underlying Cane River Formation.

The Sparta is used as aquifer is used for 15 parishes in north-central Louisiana, primarily for public supply and industrial purposes (McGee and Brantly, 2015). For the Sparta aquifer, hydraulic conductivity generally ranges from 10 to 200 feet per day (ft/d) with an average of about 70 ft/d over the extent of the Mississippi Embayment (Hosman and others, 1968). Regionally, it ranges in depth from 800 feet below NGVD 29 (Northwest corner) to nearly 2,000 feet below NGVD (Southeastern Corner) per the USGS Fact Sheet, 2015. In 2010, withdrawal from the Sparta aquifer totaled 63.11 Mgal/d (Sargent, 2011). The Sparta is most heavily pumped along the Arkansas-Louisiana border. Regional flow is towards the city of Monroe in Ouachita Parish (Figure 2-43). In the Rapides Parish sequestration site area, this system is saline. Details on the Geochemistry is contained in Section 2.7.

2.4.1.4 Cook Mountain Formation - Aquiclude

The Cook Mountain extends from north central Louisiana eastwards towards Mississippi and north towards Arkansas. The formation ranges in thickness from about 100 feet, in northeastern Louisiana, to about 300 feet, in central Louisiana, where it dips to the southeast towards the axes of the Mississippi structural trough (embayment) and the Gulf Coast Syncline (Rollo, 1960). The unit is comprised of impermeable clays and minor fine-grained sand lenses that may contain local freshwater for Parish's in the north of Louisiana.

2.4.1.5 Cockfield Aquifer

The Cockfield aquifer within the Eocene Cockfield Formation of the Claiborne Group. It consists of fine sand with interbedded silt, clay, and lignite, becoming more massive and containing less silt and clay with depth. The regional confining clays of the overlying Jackson and Vicksburg Groups confine the Cockfield aquifer. The Cook Mountain serves as the basal confining zone.

Recharge to the Cockfield aquifer occurs primarily by the direct infiltration of rainfall in interstream, upland outcrop-sub crop areas, the movement of water through the alluvial and terrace deposits, and vertical leakage from the underlying Sparta aquifer. The Cockfield aquifer contains fresh water in north-central and northeast Louisiana in a narrowing diagonal band extending toward Sabine Parish (Figure 2-44). Saltwater ridges under the Red River valley and the eastern Ouachita River valley divide areas containing fresh water in the Cockfield aquifer. The hydraulic conductivity varies between 25 and 100 feet/day.

The maximum depths of occurrence of freshwater in the Cockfield range from 200 feet above sea level to 2,150 feet below sea level. The range of thickness of the freshwater interval in the Cockfield is 50 feet to 600 feet. In summary, data show that groundwater produced from this aquifer is moderately hard and that one MCL was exceeded for the volatile organic compound methylene chloride. Data also show that this aquifer is of fair quality when considering taste, odor, or appearance guidelines, with 22 secondary MCLs exceeded in 12 of the 14 wells sampled. The Cockfield reservoir does have a few sands within the AoR that could be used for irrigation. These sands will be sampled to confirm salinity in the monitor wells

In 2005, the Cockfield Aquifer was predominantly used for public supply with 84.0 percent of the total usage. The second highest draw on the aquifer came from rural domestic use at 6.2 percent. The remaining 9.7 percent of aquifer use that year was due to livestock, rice irrigation, general irrigation, and aquaculture, each responsible for less than 5 percent of the aquifer's total use that year. Groundwater in this aquifer flows primarily towards the Ouachita River (Figure 2-45). In the Rapides Parish sequestration site area, this system is saline. Details on the Geochemistry is contained in Section 2.7. The Cockfield aquifer will be monitored for pressure at the Rapides sequestration site and is a saline buffer zone above the primary confining zone.

2.4.1.6 Catahoula Aquifer

This aquifer system overlies the Jackson-Vicksburg shale and is of Oligocene to possibly Miocene in age. It is only represented or used in a narrow band across the north-central part of the state. It is a comprised of interbedded sands and clays, deposited in a fluvial/channel environment, with many of the sand lenses discontinuous. The Catahoula aquifer generally ranges in thickness from about 50 feet in the outcrop area to about 450 feet in southern Vernon Parish (Fendick and Carter, 2015). The system is a confined and is overlain by the Miocene-aged Lena Confining Unit. Recharge to the systems is from rainfall in outcrop areas and from leakage from underlying aquifer systems.

In 2010, about 3.96 Mgal/d were withdrawn from the Catahoula aquifer in Louisiana (Fendick and Carter, 2015). Groundwater flow is generally towards the Red River, Little River and Ouachita River. Potentiometric maps (Figure 2-46) indicates that that the regional flow is not altered by public use, as this is considered a minor aquifer in Louisiana.

2.4.1.7 Lena Confining Unit

Miocene-aged clays that retard hydraulic connectivity between the Catahoula and Jasper aquifer systems.

2.4.1.8 Jasper Aquifer

The Jasper Aquifer is a hydrostratigraphic unit contained within the Miocene sands in the central and southwestern portion of Louisiana. The base of the aquifer coincides with the top of the Lena Confining Unit. The Jasper aquifer is separated from the deeper saline formation waters of the Catahoula Formation and is a is a confined system overlain by the Castor Creek Confining unit (referred to as the Burkeville Confining system in Texas and southwestern Louisiana) (Figure 2-40). Regionally, the Jasper aquifer system dips southwards and becomes deeper and increases in salinity towards the Gulf of Mexico. The system is laterally extensive throughout the southern portion of Louisiana and along the Gulf Coast of Texas.

The alternating sands and shales of the Miocene were deposited in marine to fluvial-deltaic environments. For Louisiana, the Jasper Aquifer System is only a freshwater source in Vernon, Beauregard, Rapides, and Allen Parishes. The aquifer ranges in thickness from 50 feet to 2,400 feet and is comprised of medium- to fine-grained sands. The Jasper aquifer system is geologically isolated from other aquifers by laterally extensive overlying and underlying clay strata.

Regionally, the Jasper Aquifer system is subdivided into an upper unit, the Williamson Creek aquifer, and a lower unit, the Carnahan Bayou System. In 2002, the combined withdrawal for the aquifer was 42 Mgal/d, with 22 Mgal/d from the Williamson and 20 Mgal/d from the Carnahan (Sargent, 2011). The maximum depths of occurrence of freshwater in the Carnahan Bayou aquifer range from 250 feet above sea level to 3,300 feet below sea level. The range of thickness of the freshwater interval in the Carnahan Bayou aquifer is 100 to 1,100 feet. The depths of the Carnahan Bayou aquifer wells that were monitored in conjunction with the ASSET Program range from 143 to 2,036 feet below land surface.

Heaviest use of the combined Jasper Aquifer system is from Rapides Parish. In 2015, public supply and industry uses were the predominant draws on the Jasper Aquifer with public supply with 43 percent of the total usage followed by industry with 49 percent use for a combined use of 92 percent. Figures 2-47 and 2-48 contain potentiometric maps constructed in 2003 for the Williamson Creek lower and Carnahan Bayou System. The aquifer has been heavily affected by withdrawal from Alexandria-Pineville area in Rapides Parish. Large cones of depression have been noted due to the public supply demand (Brantley and Seacor, 2005).

2.4.1.9 Castor Creek Confining Unit

The Castor Creek Confining Unit System separates the Jasper and Evangeline aquifers and retards the interchange of water between the two aquifers. This system is comprised of compacted clays and fine-grained silts, with occasional lenses of sands. This system is shown has been shown as an effective confining unit due to the differing hydrostatic pressures within the Jasper (underlying) and Evangeline (overlying) aquifers.

2.4.1.10 Evangeline Aquifer

Within Louisiana, the Evangeline Aquifer is situated within sands associated with the Pliocene-aged undifferentiated sands (the Goliad equivalent in east Texas). This aquifer underlies the extensive Chicot Aquifer System and is comprised of sands that range from loosely consolidated sands and gravels, with interbeds of silts and clays. The sands are moderately well sorted and overlay the confining Castor Creek unit in central Louisiana (Texas equivalent is the Burkeville Confining unit), retarding flow from between the aquifer systems. The upper portion of the Evangeline is separated from the Chicot by thin clay beds, but in some areas, these confining strata are missing. This puts the deeper Evangeline sands in contact with basal sands of the Chicot. Near the coast of Louisiana, this system is saline due to saltwater intrusion.

Recharge to the Evangeline aquifer is upland from the Gulf of Mexico from precipitation, and minimally, by leakage downwards from other shallow aquifers. The hydraulic conductivity of the Evangeline aquifer varies between 20 to 100 ft/day (DEQ, 2009 Triennial Summary Report).

Figure 2-49 show the regional groundwater flow from this aquifer is down dip, towards the Gulf of Mexico. In 2000, about 22 Mgal/d was withdrawn from the aquifer for public supply and industry (Sargent, 2002). Much of the withdrawal is seasonal and used for rice irrigation. In the Rapides Parish sequestration site, this aquifer and geological unit are not present.

2.4.1.11 Chicot Aquifer

The Chicot Aquifer System is the main regional aquifer system that provides usable groundwater for southwestern Louisiana (Figure 2-39). The Chicot aquifer system is largely comprised of one, major undifferentiated sand, that splits down dip. These Pleistocene-aged sands are predominately comprised of unconsolidated to loosely consolidated gravels and coarse graded sands. These sands dip and thicken towards the Gulf Coast and thin to the west (towards Texas) and slightly thicken towards the east (towards Mississippi). The aquifer system thickens and deepens to the south at a rate of about 30 ft/mile (Nyman, 1984) The upper sand section contains freshwater underlain by saltwater in Cameron Parish (Nyman, 1984), except along the southeastern coast where no freshwater is present (Smoot, 1988). A freshwater to saline interface is driven northwards from the coast by water production for public supply, rice irrigation, and aquaculture. The southern limit of freshwater in the upper aquifer occurs near the coastline (Nyman, 1984).

Recharge to the system in Louisiana occurs where the Chicot outcrops in southern Rapides and Vernon Parishes, and in the northern portions of Allen, Beauregard, and Evangeline Parishes. There is also minimal recharge to the system via vertical leakage from the shallow overlying alluvial deposits.

In southwestern Louisiana and southeastern Texas, the aquifer is sub-divided into three sub-units that are separated by confining layers. The principal sand units within the aquifer are the 200-foot Sand, 500-foot Sand, and 700-foot Sand. In the northeastern portion of the Calcasieu Parish, these sands merge and the unit contain undifferentiated sands that are conducted hydraulically. Freshwater in the lower subsections of the Chicot deteriorates in quality with depth. Low TDS concentration groundwater is predominately found in the 200-foot Sand and 500-foot Sand of the Chicot Aquifer, which is heavily used by public and industrial uses. The 700-Foot Sand contains areas of saltwater encroachment from leakage from underlying salt domes and from the Gulf of Mexico as it nears the coast.

The Chicot Aquifer yields the highest amount of groundwater for the State of Louisiana. It is the primary source of water for Acadia, Calcasieu, Cameron, and Jefferson Davis Parises. As the aquifer nears the coast, the lower units become saline and only the upper portions of the aquifer are used as a source of groundwater. Approximately 849.9 Mgal/d are produced from the entire aquifer. The largest contributor for withdrawal is for rice irrigation and aquaculture (crawfish harvesting), which are seasonal. As a result, during the off-peak irrigation season, the aquifer recharges, with the water level rebounding back to normal levels. The Chicot is also the largest supplier of public supply at 95.6Mgal/day for the southwestern region and supports large cities such as Lake Charles in the area of interest. Figure 2-50 contains a 2003 Potentiometric map for the uppermost sand (200-Foot sand) which shows groundwater flow towards areas of high populations. In the Rapides Parish sequestration site, this aquifer and geological unit are not present.

2.4.1.12 Red River Alluvial System

The Red River Alluvial Aquifer is a surficial aquifer system (Figure 2-51). The aquifer is poorly to moderately well-sorted, with fine-grained to medium-grained sand near the top, grading to coarse sand and gravel in the lower portions. It is confined by layers of silt and clay of varying thicknesses and extent. Red River Alluvial system is located within the surficial deposits that unconformably overlie deeper geologic strata.

The Red River Alluvial Aquifer is hydraulically connected with the Red River. Recharge is accomplished by direct infiltration of rainfall in the river valley, lateral and upward movement of water from adjacent and underlying aquifers, and overbank stream flooding. The amount of recharge from rainfall depends on the thickness and permeability of the silt and clay layers overlying it. Water levels fluctuate seasonally in response to precipitation trends and river stages. Water levels are generally within 30 to 40 feet of the land surface and movement is down gradient and toward rivers and streams. Natural discharge occurs by seepage of water into the Red River and its streams, but some water moves into the aquifer when stream stages are above aquifer water levels. The hydraulic conductivity varies between 10 and 530 feet/day.

The maximum depths of occurrence of freshwater in the Red River Alluvial range from 20 feet above sea level to 160 feet below sea level. The range of thickness of the freshwater interval in the Red River Alluvial is 50 to 200 feet. The Proposed Rapides Parish Sequestration site is on the southwest perimeter of the Red River Alluvial aquifer and is projected to be contained with the surficial deposits.

2.4.2 Local Hydrogeology

Northern Rapides Parish is not served by any of the primary or principal Cenozoic Paleocene-Eocene-aged subsurface aquifer systems in Louisiana. These aquifers are all saline reservoirs in Rapides, Vernon, Grant, and the south half of Natchitoches parishes. They are all sealed by the regionally thick Jackson-Vicksburg Shale above and confined internally by the confining zones of Cook Mountain Shale and Cane River Shale (Figure 2-40). These saline aquifers are the targeted CO_2 injection zones within the AoR.

The CapturePoint Solutions sequestration site is located within northwestern Rapides Parish. The deepest aquifer of used in north Rapides Parish is the Catahoula Aquifer System (Appendix B Figure B-12). This aquifer will be monitored for pressure within the AoR and will basically servs as an additional buffer for monitoring the effectiveness of the confining zones. The Miocene-aged Jasper Aquifer System contains the major sources of groundwater for the Parish, with contributions from the Catahoula and Red River alluvial aquifers. South of the site, the Chicot and Evangeline are used as sources as well but are not located at the project site.

The Lena Confining Unit is a regional confining system that hydrologically separates the Jasper Aquifer System from the underlying Catahoula aquifer. A localized cross section (A-A') (Figure 2-52), parallel to dip from Tomaszerski, 2007 (presented in the USGS Water fact sheet), depicts the hydrogeologic system across Rapides Parish, and more importantly the Kisatchie Well Field. The following units are the focus for the CapturePoint Solutions sequestration site:

- Catahoula Aquifer System
- Lena Confining Unit
- Jasper Aquifer System (Williamson Creek and Carnahan Bayou)
- Castor Creek Confining
- Red River Alluvial

Within this stratigraphic section there are two main aquifers of local interest: the Jasper and the Catahoula. The base of the lowermost USDW (defined as 10,000 ppm) is located within the Catahoula Aquifer. This aquifer system is not currently used as a source of freshwater within the site area. There are no known springs within the AoR and no upper bedrock or lower bed rock aquifers. The surficial aquifer system within the AoR is the Holocene aged Red River Alluvial Aquifer.

The hydraulic conductivity of the Catahoula aquifer varies between 20 and 260 feet/day. The maximum depths of occurrence of freshwater in the Catahoula aquifer range from 250 feet above sea level to 2,200 feet below sea level. The range of thickness of the freshwater interval in the Catahoula aquifer is 50 to 450 feet.

The maximum depths of occurrence of freshwater in the Red River Alluvial range from 20 feet above sea level to 160 feet below sea level. The range of thickness of the freshwater interval in the Red River Alluvial is 50 to 200 feet. The Proposed Rapides Parish sequestration site is on the southwest perimeter of the Red River Alluvial aquifer.

2.4.3 Determination of the Lowermost Base of USDW

The most accurate method for determining formation fluid properties is through the analysis of formation fluid samples. In the absence of formation fluid sample analyses, data from open-hole geophysical well logs can be used to calculate formation fluid salinity by determining the resistivity of the formation fluid (R_w) and converting that resistivity value to a salinity value. The two primary methods to derive formation fluid resistivity from geophysical logs are the "Spontaneous Potential Method" and the "Resistivity Method". The "Spontaneous Potential Method" derives the formation fluid resistivity from the resistivity of the mud filtrate, and the magnitude of the deflection of the spontaneous potential response (SP) of the formation (the electrical potential produced by the interaction of the formation water, the drilling fluid, and the shale content of the formations). The "Resistivity Method" determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987).

2.4.3.1 Spontaneous Potential Method

The spontaneous potential curve on an open-hole geophysical well log records the electrical potential (voltage) produced by the interaction of the connate formation water, conductive drilling fluid, and certain ion selective rocks (shales). Opposite shale beds, the spontaneous potential curve usually defines a straight line (called the shale baseline), while opposite permeable formations, the spontaneous potential curve shows excursions (deflections) away from the shale baseline. The deflection may be to the left (negative) or to the right (positive), depending primarily on the relative salinities of the formation water and the drilling mud filtrate. When formation salinities are greater than the drilling mud filtrate salinity, the deflection is to the left. For the reverse salinity contrast, the deflection is to the right. When salinities of the formation fluid and the drilling mud filtrate are similar, no spontaneous potential deflection opposite a permeable bed will occur.

The deflection of the spontaneous potential curve away from the shale baseline in a clean sand is related to the equivalent resistivities of the formation water (r_{we}) and the drilling mud filtrate (r_{mf}) by the following formula:

$$SP = -K\ Log\left(\frac{r_{mf}}{r_{we}}\right) \quad (1)$$

For NaCl solutions, K = 71 at 77°F and varies in direct proportion to temperature by the following relationship:

$$K = 61 + 0.133\,T° \tag{2}$$

From the above equations, by knowing the formation temperature, the resistivity of the mud filtrate, and the spontaneous potential deflection away from the shale baseline, the resistivity of the formation water can be determined (Figure 2-53). From the formation water resistivity and the formation temperature, the salinity of the formation water can be calculated (Figure 2-54).

2.4.3.2 Resistivity Method

The Resistivity Method determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987). The resistivity of a formation (R_t in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (infinitely high resistivity) with the exception of some clay minerals, and therefore is not generally a factor in the resistivity log response.

Induction geophysical logging determines resistivity or R_t by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987). Therefore, the induction log measures the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivity under 2 ohm-meters. Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988).

In general, high-porosity sediments with open, well-connected pores have lower resistivity, and low-porosity sediments with sinuous and constricted pore systems have higher resistivity. It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.,* one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w} \tag{3}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m} \tag{4}$$

Where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2 (Stolper, 1994). In the shallower sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease (Stolper, 1994). Experience over the years has shown that the following form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^m} \tag{5}$$

Combining the equations for the Humble relationship and the definition of the formation factor, the resistivity of the formation water (r_{we}) is related to the formation resistivity (r_t) by the following:

$$R_t = \frac{R_{we}\ x\ 0.81}{\phi^m} \tag{6}$$

2.4.3.3 Methodology used in the Site Evaluation

To determine the formation water resistivity in a particular zone, the resistivity of the drilling mud filtrate (obtained from the log header) at the depth of the zone must first be determined. Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (Figure 2-53). From this figure the resistivity of the drilling mud filtrate can be corrected to the temperature of the zone of interest. A shale baseline is next established on the spontaneous potential curve and the deflection away from the shale baseline measured. A chart containing the graphic solution of the spontaneous potential Equation (1) (Figure 2-54) gives the solution for the ratio between the resistivity of the mud filtrate and the formation water (R_{mf}/R_{we}) based on the measured spontaneous potential curve deflection. The resistivity of the formation water at formation temperature can be determined from the R_{mf}/R_{we} ratio and converted to the equivalent NaCl concentration from Figure 2-53. Once the base of the lowermost USDW is established, a formation resistivity (R_t) cut off on the deep induction log can be established using Equation (6). This formation resistivity cut-off is used to establish the base of the lowermost USDW at Rapides Parish site.

By manipulating Figures 2-53 and 2-54, a formation water resistivity of 0.35 ohm-m corresponds to a salinity of 10,000 mg/l TDS. At a temperature of approximately 90 °F, a formation water resistivity value of 0.45 ohm-m corresponds to a salinity of 10,000 mg/l TDS. Deeper intervals with higher temperatures will have a higher resistivity cut off for analysis.

From this water resistivity value and an estimate of formation porosity, a formation resistivity (R_t) cut-off can be calculated. For the Rapides Parish site, the USDW is projected to be relatively shallow, thus a formation water resistivity of 0.35 ohm-m is used. Using an assumed formation porosity of 34 percent (shallow unconsolidated sands) and solving for the total formation resistivity. From Equation (6), a formation resistivity (R_t) cut-off can be calculated if the approximate formation porosity is known. Therefore, solving Equation (6) gives the following result:

$$R_t = \frac{0.35\ ohm - m\ x\ 0.81}{0.34^2} = 2.45 ohm - m$$

Therefore, it is conservatively calculated that the sands with a formation resistivity of greater than 2.0 ohm-m were considered to be USDWs. This site-specific calculation is in agreement with the Louisiana Department of Natural Resources (LaDNR) guidance located at http://www.dnr.louisiana.gov/assets/OC/im_div/uic_workshop/2_USDW.pdf which indicates that the USDW should fall between:

- Ground surface to 1,000 feet: 3 ohms or greater is considered USDW
- 1,000 feet to 2,000 feet: 2 ½ ohms or greater is considered USDW
- 2,000 feet and deeper: 2 ohms or greater is considered USDW

This methodology was employed by reviewing shallow well logs across the Rapides Parish site. To be conservative in the current analysis, the base of the lowermost USDW across the evaluated logs was placed at the deep resistivity 2-ohms cutoff.

2.4.4 Base of the Lowermost USDW

The lowermost USDW is defined by the sudden decrease of resistivity within the Catahoula Aquifer. This is separated by more than 2,500 feet of geological intervals from Injection Zone No. 1. Figure B. 12 (in Appendix B) is a cross section of the base of the USDW across the AoR.

For the Rapides Parish site, the USDW is found to occur at a depth range of approximately 2,100 below ground level, based upon this methodology. A Lowermost USDW Map (Figure B.X13 in Appendix B) shows the depth ranges from 1,200 feet subsea at the northern margin of the AoR to nearly 2,500 feet subsea at the southern margin of the AoR. Generally, dip rates are steeper on the east flank of the AoR when compared to the center and west flank of the AoR.

Please note: the Catahoula Aquifer is not used a freshwater source within the Rapides Parish Sequestration site. It is separated from the heavily used Jasper System by more than 150 feet of the Lena Confining Shale Unit.

2.4.5 Local Water Usage

In Rapides Parish, with population of approximately 132,000 people, the main source of drinking water comes from the Jasper Aquifer System and the largest city is Alexandria. The city's water is supplied from 14 wells in the city limits and from 32 wells with the [redacted]. Water is produced from the Jasper Aquifer System (Williamson Creek and Carnahan Bayou) and from the Chicot (wells located in the southern portion of the forest). Massive withdrawal from the subsurface shows possible cone of depressions forming around the city (Figure 2-47 and 2-48).

The USGS in cooperation with the Louisiana Department of Transportation and Development (DOTD) produced a "Water Resources of Rapides Parish" fact sheet with data from 2005. The supply for public use was split between surface water (92 percent) and groundwater (8 percent). Majority of the surface water is supplied from Lake Rodemacher for the Parish. The 2005 statistic showed that 27 Mgal/d were withdrawn groundwater supply, with the Alexandria Water Supply accounting for 18 Mgal/d out of that total number.

The alluvial surface aquifers are grouped and referred to as shallower than 200 feet. The Red River alluvial aquifer is 20 feet to 80 feet thick and is present mainly along the Red River, which cuts through the Parish and is a minor contributor for water use.

The Williamson Creek (upper Jasper Aquifer System) is present in 90 percent of the Parish. The aquifer yields 20 to 550 gal/min with withdrawal averages of 4 Mgal/d in 2005. The Carnahan Bayou (lower Jasper Aquifer System) is also present throughout the parish but contains a mixture of saline to freshwater as it is deeper than the Williamson Creek. Both aquifers dip towards the south. The Carnahan Bayou aquifer yields 5 to 710 gal/min with withdrawal averages of 14 Mgal/d in 2005.

In 2015, about 770 million gallons per day (Mgal/d) were withdrawn from water sources in Rapides Parish (Figure 2-55). About 96 percent (737 Mgal/d) was withdrawn from surface water, and 4 percent (34 Mgal/d) was withdrawn from groundwater The City of Alexandria withdrew 10 Mgal/d from subsurface freshwater aquifers. Surface withdrawals for power generation accounted for 94 percent (726 Mgal/d) of the total water withdrawn. Withdrawals from ground water for other uses included public supply (19 Mgal/d), irrigation/aquaculture (7.56 Mgal/d). Groundwater withdrawals in the parish has generally been flat at 30-40 Mgal/d for the last 50 years.

2.4.6 Water Wells and Data Sets

Water well data was gathered from the online database of the Louisiana Department of Natural Resources (LADNR), specifically the online GIS website SONRIS (https://www.sonris.com/). A water well search was performed through SONRIS (Louisiana) in September of 2021. A water well records search was also conducted at the LDNR well repository in March of 2023, copies of these records are located in Appendix D. These record searches were performed to evaluate and locate all well records for wells that occur within the AoR. Water well locations present within the Area of Review of the Rapides Sequestration Site are shown on Figure 2-56. A total of 110 registered water wells are identified on the figure and keyed to Table 2-10. These wells extend from depths of 25 feet to 1,494 feet into the Caranahan Bayou Aquifer (deepest USDW penetrated). No water wells have been drilled into the Catahoula Aquifer for usage within the area. Out of the 69 active water wells, no wells are used as water supply to rigs, no wells are used for irrigation. Water wells within the AoR are used for commercial/municipal public supply, domestic purposes and monitoring purposes. No wells are used for industrial or livestock purposes.

Figure 2-56 also illustrates the surface water bodies and include part of the [redacted]. The branches and creeks are intermittent. The streams and lakes drain to the northeast into the [redacted] surface watershed. There are two abandoned sand and gravel quarries and no subsurface mines. A couple of very small surface gravel pits are possible from satellite review. Ground water usage from the active water wells would be approximately 4,000 gallons daily at 2.6 people per household with a gross usage per day at 100 gallons per person. There are approximately 110 residences scattered along the western margin and northern flank of the AoR. Municipal water would therefore serve 88 percent of the homes within the AoR.

Note: there are no Class I or Class II injection well operations within the AoR for the sequestration site. Only one Class I well is active within Rapides Parish and is located east of the Sabine River near Alexandria.

2.4.7 Injection Depth Waiver

The CapturePoint Solutions Rapides Parish sequestration site has identified injection zones deeper than the base of lowermost USDW by more than 2,500 feet. Therefore, this section is not applicable.

2.5 Seismicity

An earthquake is a motion or trembling that occurs when there is a sudden breaking or shifting of rock material beneath the earth's surface. This breaking or shifting produces elastic waves which travel at the speed of sound in rock. These waves may be felt or produce damage far away from the epicenter-the point on the earth's surface above where the breaking or shifting occurred. The size of an earthquake can be expressed by either intensity or magnitude. Magnitude is based on an instrumental recording that is related to energy released by an earthquake, while intensity describes the felt effects of an earthquake:

> **Intensity** - effect of the ground motion on man, structures, and on natural features. The measure currently in use (since 1931) is known as the Modified Mercalli Intensity Scale (MMI). Before 1931, the quite similar Rossi-Forel Intensity Scale was used. Intensity observations are employed to construct isoseismal maps wherein the areas of equal shaking are contoured.
>
> **Magnitude** - instrumental measure of an earthquake. It is the response of a specified instrument (seismograph) with narrowly defined dynamic response. With the magnitude scale, earthquakes can be measured at a distance. Seismic stations should all achieve similar determinations from the same event since adjustments are made for distance and instrumental constants. The magnitude scale was devised by Dr. Charles F. Richter. There are now several iterations of the magnitude scale, depending on the type of seismic wave observed, epicentral distance, and several other factors.

Instrumental seismology is equally as important as the historic record, for instrumentation permits measurement and location of seismic events much smaller than those which may be felt. Thus, a catalog of seismic events may contain events that are instrumentally recorded but not felt by man. Also, since seismic ground motion attenuates with distance and the entire country is not adequately covered by seismographs, many small events are felt but not recorded or escape all detection.

2.5.1 Seismicity of in the Region

Seismically, the Gulf Coastal Plain is one of the least active regions of North America (Figure 2-57). The sequestration site in Rapides Parish is found within area IV of the Modified Mercalli Intensity Scale (MMI). Within the Rapides Parish AoR, faulting is not present in the Cenozoic section. Natural seismicity in the Gulf Coastal Plain is attributed primarily to flexure of sediments along hinge-lines that parallel the coast. This flexure is due to compression and down warping of the immature Gulf of Mexico basin sediments in response to extreme sediment loading. Structural features such as salt domes and growth faults, although capable of storing and releasing some seismic energy, are weak and ineffective in generating even modest ground motion. None of these features are located near the sequestration site.

Error! Reference source not found. Rapides Parish, and neighbouring parishes, have not had a d ocumented earthquake from historical data base. (Table 2-11). Figure 2-58 is additional support and shows the tectonically stable area of Rapides Parish with subsurface faulting absent. The northern Rapides Parish geophysical data set that was interpreted for structural fabric also demonstrated that faulting above 16,000 feet was not present. Table 2-11 contains a listing of documented earthquakes in Louisiana from 1843 to 2021.

2.5.2 Seismic Risk of the Site

A preliminary seismic risk evaluation is conducted for the project area. The sequestration area is located in Rapides Parish, in an area of no faulting or salt dome movement. Overall seismic risk is rated very low based on:

- Low frequency of natural earthquake events near the sequestration area
- Low intensity of natural earthquakes felt in the sequestration area, with maximum ground motion on the surface being less than or equal to an intensity range of MMI=IV
- Low population density in near the sequestration site limit exposures and impacts
- Lack of injection-induced seismicity in Class I or Class II wells in the area
- Lack of Oil and Gas Production in the area
- There are no known faults in the AoR

Typical geologic structures characteristic of this province is gently southerly dipping and thickening sedimentary strata.

As discussed in Section 2.5.1, the seismic activity in this part of the coastal plain is among the lowest in the United States (Figure 2-57) and has only been assigned the lowest coefficients. Underground tectonic forces that are continually applied to brittle rocks tend to deform or bend the rocks slightly. In this scenario, stress in brittle rock builds up during the "interseismic" period until they rupture seismically and deforms instantaneously when the stress from the forces built-up over time exceeds the strength of the rocks. These instantaneous movements produce seismic waves that travel through the earth and along the surface of the earth and are responsible for the trembling and shaking known as an earthquake. It should be noted that none of the earthquakes that has occurred in Louisiana has been attributed to any specific fault, however, this may be due to the paucity of seismograph stations located in the state (Stevenson and McCulloh, 2001).

Based upon the low seismic risk evaluation for the site, a plan specific to earthquakes should not be required. However, the Rapides sequestration site will have a Site Emergency Response and Evacuation Plan for acts of nature which will include fire, tornado, hurricane, flood, and earthquake. Where required or applicable the site-specific Emergency Response Plan will reference the emergency procedures outlined in Facility Response Plans (FRP) and Operations, Maintenance, and Emergencies (OME) manuals. The sequestration site will also have a CO_2 Emergency Relief Plan submitted in Module E "*Emergency and Remedial Response Plan*".

As a general policy the company provides site specific Emergency Response Plans for each company site. The site-specific Emergency response plan will include

1) Procedure for reporting an emergency including hierarchy of authority
2) Procedures for emergency evacuation including type of evacuation and exit route assignments
3) Procedures to account for employees after evacuation
4) Procedures to be followed by employees who remain for facility operations prior to their evacuation
5) Name and job title for every employee who may be contacted by employees who need additional information about the plan or an explanation of their duties under the plan.

Evaluations have been performed to determine the possible effects of natural events on (1) the integrity of well construction materials; and (2) the integrity of both the Injection and Confining Zones beneath

Rapides Parish sequestration site. A review of "The National Earthquake Information Center" (http://earthquake.usgs.gov/contactus/golden/neic.php) indicates that the Rapides Parish site area has a low potential for seismic activity.

2.5.3 Seismic Risk Model

A model earthquake is used to evaluate the potential effects, if any, of natural earthquakes on structures associated with the sequestration project. In general, a source mechanism is required when designing a "model" earthquake. In these cases, it is usual to have a "known" active fault system with a measured strain or stress field. In the area of Rapides and neighboring parishes, there are no known faults, and the risk level is of the lowest (Figure 2-57).

2.5.4 Induced Seismicity

Seismicity related to fluid injection normally results from activity involving high pressures and large volumes, such as those associated with high-pressure water flood projects for enhanced oil recovery. This seismicity is caused by increased pore pressure, which reduces frictional resistance and allows the rock to fail. Fluid withdrawal has caused land subsidence and earthquakes due to dewatering and differential compaction of the sediments. Earthquakes of magnitude 3.4 to 4.3 on the Richter scale appear to have been caused by fluid withdrawal near some oil fields in east Texas (Davis et al., 1987), such as Sour Lake, Mexia, and Wortham Fields.

Since 2010, the occurrence of earthquakes with a magnitude greater than 3.0 have increased from 20 events per a year (1967-2000) to over 100 events per a year (2010-2013) in the central and eastern US region (Ellsworth, 2013). The increased rate of occurrence in previously inactive seismic areas has been correlated with the increased use of injection wells located near faults. Fluid injection induced earthquakes are most likely caused by the increased pore pressure from injection operations which have reduced effective stress of faults leading to failure. This mechanism has been used to explain the best-known cases of injection-induced seismicity which was first studied in the Rocky Mountain Arsenal near Denver. New case studies have increased with the use of wastewater injection wells associated with hydraulic fracking. In many sites, smaller seismic occurrences have shown to be precursors to larger events. More data has become available since the Rocky Mountain study in the 1960's, leading to a better understanding of factors and processes associated with induced-seismicity.

One of the most notable regional cases of induced seismicity associated with injection wells occurred in Youngstown, Ohio. In 2011, 12 low-magnitude seismic events occurred along a previously unknown fault line (Ohio Department of Natural Resources, 2012). These events occurred less than a mile from Class II injection well Northstar I. Previously, the area was seismically inactive, with earthquakes beginning a few months after the injection of wastewater. The injectable pressure at Northstar I was increased twice over six months (Ohio Department of Natural Resources, 2012) and may have reduced the effective stress on a fault. After the well was shut down by the Ohio Department of Natural Resources, the seismic activity declined. As a result of this case, seismic monitoring prior to injection and after injection has become common in Class II sites.

A case study in the Dallas-Fort Worth area tied small seismic events to a Class II injection well. Eleven hypocenters have been observed at a focal depth of 4.4 km and 0.5 km from a deep saltwater disposal (SWD) well (Frohlich et al., 2010). Injection at this well began eight weeks prior to the first recorded seismic event. A northeast trending fault is located approximately at the same location of the DFW focus (Frohlich et al., 2010). As a result of fluid injection into the disposal well, the stress upon the fault had been reduced and thus reactivated the fault (Frohlich et al., 2010). All of the seismic events associated with the DFW focus are small magnitude events (less than 3.3) and occurred very shortly after initial injection.

In Oklahoma, one of the largest earthquakes in the state's history may have been a result of wastewater injection at a Class II disposal site. In 2011, Prague, Oklahoma was the location of a 5.7 magnitude earthquake that was followed by thousands of smaller aftershocks. Wastewater had been pumped continuously into an old oil well for 17 years. As the pore spaces filled, the wellhead pressure was increased to continually inject the wastewater. This reduced the effective stress upon the Wilzetta fault located 650 meters from the well (Keranen et al., 2013). The fluid was injected into the same sedimentary strata at which 83 percent of the aftershocks originated (Keranen et al., 2013). In this case, the seismic event occurred years after the initial injection phase. Since the area was considered low risk seismically, there is no data on smaller earthquakes that may have proceeded the event in 2011.

In north-central Arkansas, multiple earthquakes have been triggered because of a Class II injection well. Since the operation of the disposal well in 2009, the site has experienced an increase from two events in 2008 to 157 events in 2011 (Horton, 2012). It was also tied to the discovery of a new vertical fault. Ninety-eight percent of earthquakes within this area occurred within 6 km of one of three waste disposal sites (Horton, 2012). The depth of the earthquake foci occurred between 6.7 and 7.6 km. Injection of fluid occurred at a depth of 2.6 km. At this disposal site, and E-W trending (Enders Fault) cut into the aquifer in which the fluid was injected and then acted as a conduit to the new fault at the depth of 6.7 to 7.6 km (Horton, 2012). The disposal wells were shut down in 2011 by the Arkansas Oil and Gas Commission. The rate and size of the earthquakes steadily decreased following the shutdown of the wells (Horton, 2012).

In Texas there are at least two known examples of previously seismically inactive areas becoming seismically active after major injection programs began. One site is located in the Central Basin Platform, near Kermit, and the other is in the Midland Basin near Snyder. In both cases, large scale, high pressure, oil field related, water flooding projects were under way, and earthquakes with a magnitude of over 4.0 on the Richter scale were recorded. Historically, induced earthquakes in Texas have not exceeded 4.6 magnitudes (Frohlich et al., 2010). Factors for an induced earthquake are limited to the distance a well is located from a fault, the stress state of the fault, and a sufficient quantity of fluids from the injection well at a high enough pressure and enough time to cause movement along the fault (Ohio Department of Natural resources, 2012).

A hydraulic conduit from the injection zone to a fault may also induce earthquakes (Ellsworth, 2013). The largest injection-induced events are associated with faulting that is deeper than the injection interval, suggesting that the increased pressure into the basement increases the potential for inducing earthquakes (Ellsworth, 2013). In all cases, faults have been reactivated at or in close proximity of Class II injection sites. In some cases, previously unknown faults have been discovered. No induced earthquakes have been known or are postulated to have been caused by Class I injection operations (Davis et al., 1987).

2.5.4.1 Induced Seismicity Analysis and Injection Site

A working model for the project is available from Class I injection well sites located along the Texas-Louisiana-Mississippi Gulf Coast, roughly extending from Corpus Christi in South Texas to Pascagoula, Mississippi. These sites include both hazardous and nonhazardous fluid effluent disposal wells that typically operate in the +/-300 to 500 gallons per minute injection range, with maximum injection approaching 1,000 gallons per minute. Many of these sites have been operating since the 1970's and a few as far back as the 1950's. The geological environments of these operations are largely identical to those anticipated in the CapturePoint Solutions proposed injection site. Typical regional geologic structures characteristic of the Gulf Coast includes gently coastward dipping and thickening sedimentary strata of Tertiary to Cretaceous age that are disrupted by radial faults originating from salt or shale piercement domes, syndepositional growth and regional fault systems, and post-depositional faults. However, in the immediate vicinity of the proposed site, there are no known faults or salt structures that impacts the injection zone strata or Area of Interest.

There is no known evidence of injection-induced seismicity or suspected injection-induced seismicity at or near any of these Class I injection facilities, many which are near high-population areas. Assessment of the potential for induced seismicity at these locations follow the methodology outlined below, using the very conservative "zero-cohesion Mohr-Coulomb failure criterion" recommended by the U.S. Geological Survey (Wesson and Nicholson, 1987). These analyses indicate very low potential for induced seismicity due to pressures resulting from the injection activity (examples such as long-term Class I injection operations at sites like Chemours Delisle, Denka Pontchartrain, INV-Orange, Lyondell Channelview, Rubicon *etc.,* among others) which are regulated by the EPA.

Known examples of injection-induced seismicity due to injection include areas in the Fort Worth-Dallas area of Texas, Youngstown, Ohio, Central Oklahoma, and north-central Arkansas. These areas with known cases of induced seismicity are hydro-mechanically very dissimilar to those found in the sequestration area and are often in areas of critically stressed faults. Additionally, the sequestration project will be injecting into sandstones of the Sparta and Wilcox Formation, which are located many thousands of feet above the crystalline basement complex. Injection into strata near or at the basement, with activation of pre-existing faults, has been identified as contributing to induced seismicity in those parts of the country where deep injection occurs. Despite the long history of Class I and Class II disposal along the Texas-Louisiana Gulf Coast, there is no regional-scale or operational trends associated with induced seismicity in or near the sequestration project or in similar hydro-mechanical areas such as those documented in Skoumal et al. (2018) and Weingarten et al., (2015).

CapturePoint Solutions employs conservative assumptions to the causative mechanisms of induced seismicity and the geomechanical conditions within the Rapides Parish area of interest to conservatively constrain parameters. The potential for induced seismicity at the proposed injection site can be evaluated using the very conservative "zero-cohesion Mohr-Coulomb failure criterion," recommended by the U.S. Geological Survey (Wesson and Nicholson, 1987). This method is based on the following equation:

$$P_{crit} = \frac{S_v(3\alpha - 1)}{2} \qquad (1)$$

Where:

P_{crit} = the critical injection zone fluid pressure required to initiate slippage along faults and fractures

S_v = the total overburden stress (which represents the maximum principal stress in the Gulf Coast region)

α = the ratio of the minimum principal stress (horizontal in the Gulf Coast region) to the maximum principal stress (overburden stress)

Inherent in Equation (1) are a number of conservative assumptions, guaranteed to produce a worst-case lower bound to the critical fluid pressure for inducing seismicity. These are:

1) It neglects the cohesive strength of the sediments

2) It assumes that a fault or fracture is oriented at the worst possible angle

3) It assumes a worst-case value of 0.6 for the coefficient of friction of the rock (see Figure 4 of Wesson and Nicholson, 1987)

For present purposes, Equation (1) can be expressed in a more convenient form by introducing the so-called matrix stress ratio (K_i) (Matthews and Kelly, 1967; Eaton, 1969), which is defined as the ratio of the minimum to the maximum "effective" principal stresses. Effective principal stress is equal to actual principal stress minus fluid pore pressure (p_o). Thus:

$$K_i = \frac{\alpha S_v - p_o}{S_v - p_o} \qquad (2)$$

Substituting Equation (2) into Equation (1) yields:

$$\Delta P_{crit} = \left(\frac{3K_i - 1}{2}\right)\left(S_v - p_o\right) \qquad (3)$$

where ΔP_{crit} is the critical injection zone pressure build-up required to induce seismicity, with:

$$P_{crit} = p_o + \Delta P_{crit} \qquad (4)$$

Equation (3) will be used to evaluate induced seismicity at the Rapides Parish sequestration site.

Initial plots at the injection depths evaluated 40 pressures for a pressure gradient in the across the intervals. The analysis determined an initial pore pressure (p_o) of 0.455 pounds per square inch (psi) per foot of depth. Eaton (1969) provides a plot of the effective overburden stress (S_v) as a function of depth for locations along the Gulf Coast. This plot indicates S_v values exceed 0.90 psi/ft for the injection interval reservoirs. Matthews and Kelly (1967) provide a plot of the matrix stress ratio (K_i) for tectonically relaxed reservoir sediments along the Louisiana and Texas Gulf Coast. CapturePoint Solutions wells will be completed across the Sparta and Wilcox formations at depths ranging from 4,600 feet to 9,000 feet (approximate). Therefore, the P_{crit} for the upper most injection interval is calculated as the most conservative depth to determine critical pressure to induce seismicity (Table 2-12).

The conservatively calculated critical pressure increase required to induce seismicity on a pre-existing fault for each Injection Intervals sand for the Rapides Parish sequestration site are contained in Table 2-12. This value is significantly higher than any of the expected and modeled pressures at the injection site. Since there are no known faults or fractures within the AoR for this project, induced seismicity will not be a problem at the sequestration project.

2.5.4.2 Estimated Fracture Gradient of the Injection Zones

The fracture gradient for Injection Intervals can be estimated using Eaton's Method (Eaton, 1969). For this Class VI application, the methodology follows that as presented in Moore (1974):

$$FG = \frac{\left(P_{ob} - P_r\right)e}{\left(1 - e\right)} + P_r$$

Where:

FG	=	Fracture Gradient
P_{ob}	=	Overburden Gradient (Figure 11-11 in Moore, 1974) - depth dependent
P_r	=	Reservoir Pressure Gradient (original)
e	=	Poisson's Ratio (Figure 11-12 in Moore, 1974) – depth dependent

The nomographs presented in Moore (1974) are solved for all injection intervals at the Rapides Parish site using the top of the formations in the offset well [redacted]. An example calculation is included for the shallowest Injection Zone 1 – [redacted]:

$$FG = \frac{(0.9042 - 0.455) * 0.3983}{(1 - 0.3983)} + 0.455$$

$$= \quad 0.75 \text{ psi/ft}$$

Using the calculated fracture gradient of 0.75 psi/ft, the fracture pressure for the top of the Injection Zone 1 – [redacted] is estimated to equal [redacted] psi at [redacted] feet. Table 2-13 contains the estimated fracture gradients for all injection intervals.

2.6 Geomechanics

Preliminary geomechanical data is obtained from regional literature sources and Department of Energy Partnership Projects. Preliminary petrophysical data is also obtained from regional literature sources and Department of Energy Partnership Projects and log analysis of wells located within [redacted] miles of the project area. Open hole logging data was used to perform a petrophysical evaluation using Techlog Wellbore Software Platform software. The majority of the wells only contained SP, Resistivity and Compressional Sonic data; therefore, the interpretation was focused on estimation of lithology, Vshale, Porosity, Permeability, and capillary pressures. Due to the lack of density and shear logs, only analogue data was used for rock mechanical properties estimate.

To achieve the correct characterization of the overlying containment zones, through the injection zones and underlying Midway shale, an enhanced log suite is needed as well as a detailed geomechanical testing program to be performed in conjunction with the installation of one or more of the Class VI injection wells and or/ associated monitoring wells. A testing procedure for obtaining *in situ* geomechanical data across the Injection Zone and the Confining Zone and laboratory analyses of recovered whole and rotary core samples is detailed in Module D "*Pre-Operational Testing Plan*".

2.6.1 Shale Ductility

In Earth Science, ductility refers to the capacity of a rock to deform to large strains without macroscopic fracturing. Unconsolidated sediments are mechanically weaker than lithified rock, but their ductility provides certain advantages for carbon storage. For sealing units (confining zones), stress in unconsolidated sediments is typically accommodated by creep behavior promoted by high clay contents that induce self-sealing behavior This has major implications on the suitability of confining zone units because ductile deformation of clay/mudstone seals potential leakage pathways to the surface. These include natural pathways such as faults, and man-made pathways such as well boreholes (Clark, 1988).

1. Ductile deformation is typically characterized by diffuse deformation (i.e., lacking a discrete fault plane) and is accompanied on a stress-strain plot by a steady state sliding at failure, compared to the sharp stress drop observed in experiments during brittle failure.

The ductility of a shale top seal is a function of compaction state. Uncompacted, low-density shales are extremely ductile and can thus accommodate large amounts of strain without undergoing brittle failure and loss of top seal integrity. Highly compacted, dense shales are extremely brittle and may undergo brittle failure and loss of top seal integrity with very small amounts of strain.

Figure 2-59 shows the relationship between ductility and density for 68 shales built by Hoshino et al (1972). The ductility of the shales was measured in the laboratory at confining pressures of 1, 200, and 500 kg/cm^2 (i.e., 14, 2,845, and 7,112 psi). All samples were deformed in compression.

Density Constraints

The ductility can be inferred from the density of the material. Denser shales, such as those greater than 2.1 g/cm^3, are more brittle and can withstand less strain before fracturing. Less-dense shales, such as those less than 2.1 g/cm^3, are more ductile and can withstand larger strains before fracturing.

Pressure Constraints

Additionally, ductility of a material increases with increasing confining pressure. The ductility of a shale top seal decreases with progressive burial, compaction, and diagenesis within a sedimentary basin. The mechanical properties are not constant but change with the progressive burial as the top seal is converted from a mud to a rock. The ductility of a shale top seal also increases in response to increasing confining pressure. Thus, a shale with constant mechanical properties will have a lower ductility at shallow depths than at greater depth. Since a shale top seal does not have constant mechanical properties with progressive burial, compaction decreases ductility at the same time as confining pressure increases ductility.

Depth Constraints

Figure 2-60 from Hoshino et al (1972) shows density and shale ductility vs. brittleness as functions of depth. Laboratory data are plotted on a shale compaction curve showing density vs. depth. The figure shows the ductility of each shale at that depth (or confining pressure), with ductile samples displayed as gray circles and brittle samples displayed as black circles. Ductile shales did not fracture; brittle shales did fracture. A low-density shale at a depth of 500 m is more ductile than a highly compacted shale at a depth of 5,000 m in the center of the basin. In other words, identical traps, one from a graben deep and one from an adjacent marginal platform, will present different seal risk.

Time Constraints

Ductility changes not only with depth of burial but also with time and progressive subsidence. A shale top seal now buried at 4,000 meters and having a density of 2.6 g/cm^3 was once buried at a shallower depth and had a lower density. This now-brittle seal was once ductile.

Predicting Paleoductility

To predict paleoductility, we must know both the density and the confining pressure at the time of deformation. A database of top seal mechanical properties over a range of pertinent confining pressures is a basic tool for seal analysis. Ductility-time plots can be constructed from shale compaction curves and burial history curves. Burial history curves give the depth of burial of a top seal at a specific time. Shale compaction curves let us infer the shale density at a specific depth of burial and time

Figure 2-61 is a ductility-time plot for an Upper Jurassic top seal in the Central Graben, North Sea. The plot shows the paleodensity and inferred paleoductility during progressive burial of shales at the 141- and 151-million-year (m/y.) sequence boundaries. Prior to approximately 100 m.y., the Late Jurassic shale top seal had a density of three and was ductile. Strain prior to 100 m.y. would not contribute to seal risk. Any deformation occurring after 100 m.y. could have caused fracturing, given sufficiently high strains.

Site Examples

The ductility of clay/shales both in the Injection Zones and in the Confining Zone is a function of compaction state. Low-density shales are extremely ductile and can thus accommodate large amounts of strain without undergoing brittle failure and loss of integrity. However, highly compacted, dense, deep shales may be extremely brittle and undergo brittle failure and loss of integrity with very small amounts of strain.

Gulf Coast shales are known to exhibit viscoelastic deformational behavior that causes natural fractures to close rapidly under the action of in-situ compressive stresses (Neuzil, 1986; Bowden and Curran, 1984). Evidence of this includes rapid borehole closure often encountered while drilling and running casing in oil and gas wells along the Gulf Coast (Johnston and Knape, 1986; Clark et al., 1987). Furthermore, older abandoned boreholes have been observed to heal (close) across such shale sections to the extent that the re-entry of such boreholes for the purposes of testing deeper intervals requires the drilling of a new borehole through such viscoelastic shales (Clark et al., 1987).

This property of viscoelastic deformation behavior will cause any fractures and/or faults to close very rapidly in response to the in-situ compressive stresses, like squeezing into the fault plane from both sides. This well-known ductile (or plastic) behavior of the geologically young Gulf Coast shales is amply demonstrated by the presence of shale diapir structures and the natural closure of uncased boreholes with time (Johnston and Greene, 1979; Gray et al., 1980; Davis, 1986; Clark et al., 1987; Warner and Syed, 1986; and Warner, 1988). Jones and Haimson (1986) have found that due to the very plastic nature of Gulf Coast shales, faults will seal across shale-to-shale contacts, allowing no vertical fluid movement along the fault plane.

In 1991, the DuPont Sabine River Works Plant (now known as the INV – Orange Site located approximately 100 miles south-southwest of the study area) conducted a borehole closure test at the Orange Dome field. This closure test demonstrated the plastic nature of the Tertiary-aged Gulf Coast shales and the rapidity of shale movement to seal off open areas in the subsurface. The objective was to test the natural healing of boreholes through clay/shale sections due to clay swelling and creep and to quantify natural borehole closure (Clark et al., 2005). The test conclusively demonstrated that the young Miocene shales of the Gulf Coast will flow and seal off an open area in the subsurface in a very short time period (test duration was approximately one week) (Clarke et al, 1991).

2.6.2 Stresses

The Gulf Coast Basin is generally considered to be a passive margin with an extensional (normal) stress regime. In a normal stress regime, the vertical stress is the greatest stress (maximum principal stress and is equal to the rock overburden). The average overburden stress gradient for normally compacted Gulf Coast Sediments ranges from about 0.85 psi/ft. near the surface to about 1.0 psi/ft. at depths of about

20,000 ft. (Eaton, 1969). Sedimentary rocks along the central portion of the Gulf Coastal Plain, experience predominantly normal faulting, with SH_{max} oriented sub-parallel to the coastline (Snee and Zoback, 2020), with the least principal stress (Sh_{min}) oriented orthogonal to the coastline. Published data has been used to set the orientation of the principal horizontal stresses (Meckel 2017, Nicholson 2012 and Zobeck 1980) using regional fault-strike statistics (Figure 2-62).

The project area is located within an area of unfaulted homoclinal dip of strata off the southeast flank of the Sabine uplift. There are no faults located within the AoR of the project site.

Geomechanical stresses have been pulled from regional literature review and are contained in Table 2-14.

2.6.3 Pore Pressures

The vertical distribution in pore pressures recorded and reported for Wilcox oil and gas producing fields is available from the Mississippi Geological Society (1969). The producing Wilcox fields are located in the adjacent counties just over the Mississippi River from Rapides Parish (within a radius of 30 to 100 miles) and encounter the Wilcox at depths similar to the sands proposed for sequestration. Original field pressures are available for 40 reservoirs ranging in depths from 3,759 feet to 7,648 feet. A best-fit linear trendline indicates pore pressures of 0.455 psi/foot of depth (Figure 2-63). The regression model to the reservoir pressures indicates that the data is unbiased and the coefficient of determination for the Wilcox field pressure is approximately 0.95, indicating a high goodness of fit. There are no outliers (high or low pressures) identified in the data set.

A vertical pressure profile in the project area will be determined during well installation of the Class VI injection wells and the stratigraphic test well. A testing procedure for obtaining formation pressures is detailed in Module D "*Pre-Operational Testing Plan*".

2.7 Geochemistry

The data collection program contained in Plan *"Pre-Operational Testing and Logging*" (submitted in Module D) will be designed and implemented to fully characterize mineralogy in the Injection and Confining Zones, as well as the interstitial formation fluids. Based on select investigations performed for the Department of Energy Regional Partnerships and regional analogues, no compatibility issues are predicted in the reservoir formations.

Sands below the base of the lowermost USDW and down to the base of the Wilcox all contain saline brines. Open hole log analysis techniques are used to define the vertical distribution in concentration of the formation brines. These calculations are performed using Techlog Wellbore Software Platform software on the Chesapeake Operating Incorporated USA-LROC 34 #1 well located in Section 34 of Township 2 North, Range 2 West.

2.7.1 Methodology for Salinity Determination

The methodology is very similar to the USDW determination detailed in Section 2.4.4. The general theory in determining water quality in clean water-bearing zones flows from the formation water resistivity (R_w), which can be calculated by using the Archie equation (Schlumberger, 1988). The underlying assumption in the Archie equation is that the zone or permeable bed in which water resistivity is to be determined is 100% water saturated and must not contain any clay or shale (*i.e.*, clean sand). It is further assumed that the bed is sufficiently thick so that the deep investigation resistivity open hole geophysical logging tool is not affected by shoulder beds or is affected by mud filtrate invasion.

The general form of the water saturation equation is:

$$Swn_W^n = \frac{R_w}{(\phi^m \; x \; R_t)}$$

where:

S_w = water saturation of the uninvaded formation

n = saturation exponent, which varies from 1.8 to 4.0 but normally is 2.0

Rw = formation water resistivity at formation temperature

Φ = porosity

m = cementation exponent, which varies from 1.7 to 3.0 but normally is 2.0

R_t = true resistivity of the formation, corrected for invasion, borehole, thin bed, and other environmental effects

In shaly rocks, the Archie law over-estimates the water saturation. Many models have been developed that consider the shale volume ("Vshale") in the formation matrix to account for the excess in conductivity. As an example, the Simandoux equation (1963) is among the most used ones and reduces mathematically to the Archie equation when the formation is clean (*i.e.*, Vsh=0).

In the case of a fully saturated formation, the resistivity (R_t in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (*i.e.*, has infinitely high resistivity) and therefore is not generally a factor in the resistivity log response. Induction geophysical logging determines resistivity or Rt by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987).

Therefore, the induction log is considered to measure the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivities under 2 ohm-meters.

Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988). In general, high-porosity sediments with open, well-connected pores have lower resistivity and low-porosity sediments with sinuous and constricted pore systems have higher resistivity. It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.*, one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m}$$

where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2. In the nearer surface sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease. Experience over the years has shown that the following form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^2}$$

By combining the two equations:

$$\frac{R_t}{R_w} = \frac{0.81}{\phi^2}$$

Resistivities of saline solutions vary as a function of NaCl concentration and temperature. The relationship between temperature, NaCl concentration, and resistivity are typically shown in the form of a nomograph for computational ease (Figure 2-53).

2.7.2 Formation Brine Properties

No wells have been drilled within Rapides Parish for this Class VI permit application as of initial submittal. Formation fluid samples will be collected from each injection interval an analyzed according to the *"Pre-Operational Testing and Logging Plan*", which is submitted in Module D. Plan D.1 accounts for additional geological data to be acquired during the drilling and testing of a stratigraphic well and the injection wells. Therefore, the nearby well, [redacted] in Rapides Parish Louisiana, [redacted] miles southeast of the site, was used to estimate the expected salinity of potential injection intervals using the methodology described above. The Water Resistivity (R_w) was calculated from the Density Neutron Porosity and Deep Induction Log Curves. The calculated R_w was plotted versus depth to identify approximate values of R_w by stratigraphic interval (Figure 2-64). For the [redacted], changes in salinities are assumed to represent compartments.

For the following calculations, mid-point depths were selected as reference depths. Additionally, for the [redacted], two depths (to represent the varying salinities) were selected. The reference depths are contained in Table 2-15.

2.7.2.1 Temperature

Obtaining reliable temperature data from existing regional data, and not directly from a stratigraphic test, well is challenging. In USGS Open file Report 2019-114 (Burke et al, 2020), it was recognized that while bottom hole temperature measurements are useful for the characterization of a subsurface thermal regime, they are not without problem. Geographically, variability exists and areas with similar characteristics can be grouped together for ease of gradient calculation. Due to both the nature of the borehole radius and fluid invasion (mud filtrate) the temperature measured at the borehole and attenuates over time (Poulsen et al., 2012). These temperatures are affected by the time duration between the end of circulation and the time the logging tool actually reaches the drilled bottom of the well. As such, they are likely to represent cooler than actual temperatures, as the mud column has not had sufficient time to reach temperature equilibrium.

In Burke et al. (2020), this need for the correction of the bottom hole temperature to account for these factors has been addressed, specifically for the onshore Gulf of Mexico region of the US. The study established a unified correction over 12 outlined physiographic provinces from Texas, Louisiana, Southernmost Arkansas, Mississippi and Alabama. The proposed location of the Rapides Parish injection sits between two of these provinces, the Monroe Uplift and Southern Louisiana Salt Basin Provinces. Averaging the two gradients assigned to each yields a corrected temperature gradient of 1.49°F/100 ft. Using this gradient (1.49° F/100 ft), and a mean annual surface temperature in Rapides Parish of 67 °F, the estimated subsurface temperature for each interval can be calculated as follows (Figure 2-54):

[redacted]

From the literature, temperatures for the Wilcox, in Louisiana range from as low as 80° F to ~300° F (Dutton & Loucks, 2014), and the expected temperatures calculated from the gradient obtained from literature fit within this range.

2.7.2.2 Salinity

The calculated R_w, and corresponding temperature information were plotted on the Schlumberger Gen 9 nomograph to approximate the expected salinities of the proposed injection formations, the Sparta and Wilcox. The interpreted values are captured in the table below (Table 2-15).

In central Louisiana, the TDS of the basal [redacted] is the highest (> 40,000 mg/L). To the north of Rapides parish, TDS values calculated for the basal sand of the [redacted] range from 40,000-80,000 (mg/L). Produced water from [redacted] wells along the border of northeast Rapides Parish and Avoyelles Parish have TDS values between 125,000-150,000 (mg/L). Produced water TDS values from [redacted] wells to the south of Rapides Parish in Evangeline Parish are lower, ranging from 75,000-125,000 (mg/L). While the TDS generally increases with depth in the [redacted], there are documented cases ([redacted] in Beauregard Parish) where the TDS decreases with depth. This suggests a lack of interconnectivity between some sands within the [redacted] (Carlson and Van Biersel, 2009).

2.7.2.3 Viscosity

Viscosity is the tendency of a fluid to resist flow. The approximate formation brine viscosity at reservoir conditions is determined using a Microsoft EXCEL spreadsheet correlation as a function of pressure, temperature, and NaCl content developed by Douglas M. Boone in 1993. At the assumed formation conditions, the injection interval water (brine) viscosities are expected to be approximately:

[redacted]

2.7.2.4 Additional Properties

Also reported in the literature are values for key fluid properties in the [redacted] from LaSalle Parish, located ~45 miles from northwest Rapides parish. The pH values sampled from the area in and around Olla field range from 6.7 to 7.7. Alkalinity values ranged from 4.7 meq/kg to 56.4 meq/kg. Finally, chloride concentrations ranged from 558 mM to 2,056 mM. The chloride concentrations were found to generally increase with depth in the study.

2.7.3 Compatibility of the CO_2 with subsurface fluids and minerals

While no direct evaluation of CO_2-brine interactions within the study area has taken place, to the northeast, in the adjacent LaSalle parish, a CO_2 flood for EOR was undertaken in the Olla Field between 1983-1986 (Figure 2-31). The CO_2 was injected into the Middle Wilcox sandstone known as the 2,800-foot sand. The Wilcox sands at Olla Field are described as predominantly siliciclastic with 15-20% clay matrix (Shelton, McIntosh, Warwick, & Zhi Yi, 2014).

Between March 1983 and April 1986, 7.646 billion cubic feet (BCF) of immiscible CO_2 was injected into the 2,800-foot sand for enhanced oil recovery (EOR). The project resulted in an increase of more than 50% in the predicted expected ultimate recovery (EUR). Some CO_2 did break through to producing wells, but upon conclusion of the project, 0.09 km3 (3.175 BCF) of CO_2 was left in the sand (Shelton J., 2016).

The study showed some of the CO_2 that was left in the sand was present dissolved in the formation brines, stored by gas phase trapping. It also showed that the CO_2 did not move through the formation uniformly, rather, as expected, was influenced by the varying porosity and permeability (Shelton, McIntosh, Warwick, & Zhi Yi, 2014).

In the absence of major structural features such as faults, a key interaction of concern between the CO_2 and the rock of the confining interval, is the potential for the CO_2 to exceed the capillary entry pressure. If the CO_2 breaches the cap rock the plume could potentially leave the reservoir, migrating upwards into layers above the USDW (Gaus, 2010). However, the nature of shale (due in part to the small pore size) imparts a high capillary entry pressure, and also high viscous drag. These properties prevent the upward migration of CO_2 into the caprock. The acidification of the brine may allow the buoyant CO_2 plume to modify the initial pore structure of the cap rock. The impact and degree of these modifications depends on the kinetics of the reaction for a specific site and the degree of heterogeneity of the cap rock (Espinoza & Santamarina, 2017).

Interactions between CO_2 and the rocks in the subsurface may be categorized as those during the period of injection or immediately following injection, and interactions that occur over the long term of CO_2 storage. While the interactions occurring during injection and in the early phase of CO_2 sequestration can be directly studied and evaluated, the interactions that happen over geologic time can be evaluated through modeling and other forms of prediction. Although direct data for the proposed site location does not exist, the sampling program has been designed to include fundamental testing to evaluate key geochemical parameters in Module D "*Pre-Operational Testing Plan*".

The main drivers of CO_2-rock interactions are the dissolution of the CO_2 in the brine, acid induced reactions, reactions caused by changes in the brine concentration, clay desiccation, CO_2 and rock interactions, and the potential for other reactions caused by gasses present other than CO_2. Evaluation of the impact of CO_2 on injection and seal interval rocks and cements and the identification of potential additional reaction pathways can be evaluated for a specific site location and specific CO_2 stream to be injected. Evaluation of the interactions along operational interfaces (*i.e*. the wellbore, cements, host rock and cap rock) also need to be evaluated for both CO_2 and acidified brine (Gaus, 2010). The sampling program has been designed to include these tests on both injection interval and caprock (See *"D.1 – Pre-Operational Testing*", which is submitted in Module D).

2.8 Economic Geology of the Area

The proposed site is located north of the Lower Cretaceous Shelf Edge on continental basement blocks that separate the interior salt basins from the Gulf of Mexico salt basin. The area has been actively explored for hydrocarbons since the 1920's. The Wilcox formation was the targeted exploration object during the first 50 years of exploration in the area. The three Wilcox penetrations within the proposed AoR were drilled, dry and abandoned in the mid 1970's. Over the last 50 years deeper targets have been explored in the study area. All wells have been dry holes. Two abandoned sand and gravel quarries are located within the AoR in Section 10 T3N R3W. Over 125 wells were evaluated, for the area's structural and depositional style. 87 miles of 2-D data was purchased to collaborate structural and depositional trends. North-south Cross Section A-A' in Blue and east west Cross Section B-B' in Red analyzie the region. South of the study area is a fairway of productive horizontal wells producing oil from the Austin Chalk. Masters Creek Field has been the most prolific field. The productive trend is around 25,000 acres with approximately 100 wells completed.

2.9 Site Suitability Summary

The Northwestern Rapides sequestration site is located within a broad syncline that dips less than 2 degrees to the south. This prospective area for CO_2 sequestration covers multiple counties and could be developed as a central Louisiana regional sequestration site. This local embayment or trough is north of the Cretaceous shelf edge and located between the Sabine Arch to the northwest and the LaSalle Arch to the northeast. Due to the area's synclinal nature, hydrocarbon exploration over the last 100 years has been limited. Well density averages approximately three wells per township. The proposed injection interval is the clastic rich [redacted]. This proposed sequestration site is located along the western flank of the ancestral Mississippi River and is known as the [redacted] system of late [redacted] age.

The [redacted] saline sands are found at depths of [redacted] feet. The gross sequestration interval (Figure 2-23) is approximately 4,550 feet with porous and permeable sands encompassing nearly 40 percent of the interval. In northwestern Rapides, these sands are dominantly marine to deltaic in origin. These marine sands will generally strike northwesterly, and the deltaic sands will strike northeasterly. The marine sands will pinch out to the northwest due to the positive structural influence of the Sabine uplift during deposition. Consequently, regionally preferred flow paths are limited in the marine sands. The [redacted] prograde out onto the delta front muds from the north and northeast azimuths. Therefore, regionally the northeast quadrant of the AoR has the highest probability of preferential flow. We have positioned the dual-purpose Stratigraphic test/ Injection zone monitor well #3 northeast of the injection wells to monitor the plumes' reaction to this possible preferred regional flow path. The deltaic sands, especially the delta lobe complex which includes delta front distributary mouth bars and delta front sands will hold the greatest CO_2 storage capacity and therefore will have the greatest perforation density. The [redacted] located at the top of the [redacted] injection zone 2 and the [redacted] in injection zone 1 will have enhanced porosity and permeability values due to their overall deposition within a sea level rise. Regionally, porosities average in the high 20's and permeabilities could easily average 250 md within the AoR based on regional permeability trends. 2-D seismic's acoustic impedance processing gives a qualitative view of where these thicker deltaic sands are located within the AoR.

The proposed Northwestern Rapides Site has a total of five confining zones. There are two upper confining zones, one basal confining zone along with two internal confining zones. The two internal confining zones isolate the three discreet injection zones of [redacted], Injection Zone 1, [redacted], Injection Zone 2, and [redacted], Injection Zone 3. This isolation will enable the sequestration project to monitor the injection zones individually. Drilling risk and injection risk will be mitigated by developing the lower injection interval ([redacted] Injection Zone 3) first and either moving up-hole or drilling additional injection wells higher in the stratigraphic sequence. It is our belief that this type of injection control is unique to the onshore Louisiana north of the Cretaceous Shelf edge. The [redacted] is the site's basal confining zone. The [redacted] is regionally pervasive and averages 850 feet thick over the proposed site. The upper confining or primary confining zone is the [redacted] at an average thickness of 280 feet. The [redacted] is also regionally pervasive. A secondary confining zone is also present. The [redacted] confining zone, is over 700 feet in thickness and is located directly below the USDW within the proposed site's AoR. Between the [redacted] Injection zone 1, and the [redacted], Injection zone 2 is the confining zone [redacted]. Between the [redacted] injection zone 2 and [redacted] injection zone 3 is the confining zone [redacted]. The [redacted], [redacted], [redacted] and [redacted] are all regional confining zones within the Gulf Coast interior basins. The [redacted] is a local confining zone in south central Louisiana. The regional permeability data that we have located for the confining zones illustrate permeability is less than 1mD. This regional data set will be further enhanced from cores taken from the stratigraphic test well.

The [redacted] are both rich in saline sands with an average sand composition of approximately 40 percent. The total net sand values for the three injection intervals are estimated to be between 1,550 feet and 1,750 feet. The stratigraphic test will confirm the regional assessment that these sands have the thickness, porosity, and permeability for annual storage of [redacted] million metric tons annually and a total storage capacity of [redacted] million metric tons. A quantitative approach of using the acoustic impedance data to identify the location of the prograding delta lobes will assist in high grading injection intervals. Project injection duration is estimated at 20 years. Fortunately, faulting is very rare regionally within the targeted storage reservoir and faulting is not present in the Rapides One CCS Site AoR.

A secondary confining zone is not required as the [redacted] Formation will be found to have all the required properties for an excellent seal per the stratigraphic test well. However, the [redacted] will be a secondary confining zone. At an average thickness of 750 feet, The [redacted] will further reduce the probability of any USDW contamination from CO_2.

CO_2 has been injected in sands with similar compositional lithologies and saline water characteristics throughout the many Gulf Coast tertiary floods without any compatibility problems. Therefore, there is a very low probability of the CO_2 stream reacting detrimentally with the injection or confining zones. This hypothesis will be confirmed from the testing on the injection and confining intervals from the stratigraphic test.

The preliminary CO_2 plume modeling demonstrates limited movement of the plume after injection has ceased due to the areas low formational dip rate. Limited wildcatting within the AoR has produced only dry holes. Three Wilcox dry holes have been drilled within the AoR during the early 1970's. A review is under way to determine if reentry is required for additional well bore isolation.

The sites proximity to the regional data sets from oil and gas operations on the uplift and arch clearly reduce the risk for any assumption that has been made. The regional petrophysical data used in the preliminary reservoir modeling analysis supports the rate and storage capacity numbers obtained. We believe these modeling estimates will be confirmed as conservative as additional petrophysical data is acquired. Total CO_2 storage for the northwestern Rapides site is conservatively estimated at 500 Mmt with an additional 200 Mmt of additional storage probable within the confines of the Area of Review. Greater accuracy for the petrophysical parameters will be forth coming after the drilling of the stratigraphic test well.

The site will be surveyed for archeological or cultural sites, threatened or endangered species. The proposed site is located [redacted].

In summary, the site's injection depth, three discreet injection intervals, over 1,600 feet of prospective reservoir saline sands and five confining zones all contribute to a sequestration site with excellent reservoir management potential. The sites' synclinal location has helped reduce the number of wells drilled for hydrocarbon exploration to approximately three per township, an extremely low penetration rate by gulf coast standards. An 85 mile 2-D seismic grid demonstrates typical gulf coast faulting is not present within the AoR's Tertiary section. The areas extremely low potential for seismicity coupled with an injection interval over 7,000 feet from basement generates a safe, high storage capacity sink for a super-regional sequestration site.

3.0 AoR and Corrective Action

The fully completed AoR and Corrective Action Plan Report has been submitted via the GSDT in '*Confidential Business Information*' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

The report covers in detail the computational modelling approach to the delineation of the Area of Review (AoR), the Corrective Action Plan relating to existing well penetrations within the AoR and the Reevaluation Schedule for AoR delineation once operations commence. A thorough review of the geology and the hydrogeology was also supplied as an appendix to the main report, along with a comprehensive bibliography of references utilized during the AoR modelling execution and reporting phase.

The AoR and Corrective Action Plan Report satisfies rule requirements 40 CFR 146.82(a)(13), 146.84(b) and 146.84(c).

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

CapturePoint Solutions LLC (CPS) is providing financial responsibility pursuant to 40 CFR 146.85. CPS expects to be utilizing any one of or a combination of (1) Surety Bonds, (2) Trust Account or (3) Insurance to cover the costs of potential corrective action, emergency and remedial response, injection well plugging, post-injection site care, or site closure. The required information has been submitted via the GSDT in '*Confidential Business Information*' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection Well Construction

Pursuant to 40 CFR 146.82(a)(9), (11), and (12) and 40 CFR 146.86 injection wells will be constructed in a manner that utilizes CO_2 resistant materials and permit the use of downhole tools and gauges and be designed to accommodate workover equipment. Wells will be constructed using a 80 ft conductor, 2,650 ft of surface casing set to below the lowest USDW with production/longstring casing set to a depth of ~9,800 ft. At each phase of construction casing will be cemented to surface. The production/longstring portion of the offset in-zone monitoring well will be fitted with DTS/DAS fiberoptic sensors to monitor changes in temperature and pressure.

5.1 Introduction

The construction details for [redacted] injection wells ([redacted]) are described in this attachment. All injection wells that will be drilled to a total depth of 9,800 feet and will be completed within their targeted injection zone. These wells will be completed in accordance with 40 CFR 146.86. The drilling and completion of these wells will be sufficient to permit the use of appropriate testing devices and workover tools. Materials used in the construction of these wells will be CO_2 resistant and of sufficient structural strength to meet construction requirements.

5.2 Construction Procedures [40 CFR 146.82(a)(12)]

The drilling and completion of injection and monitoring wells will be completed in such a manner to meet 40 CFR 146.82 (A)(12) and 146.86(b) and to prevent the movement of formation and injection fluids into or between USDWs. During drilling, fluid levels will be monitored, and the appropriate mud weights used to control the movement of formation fluid, detailed information regarding fluid movement and well control events are addressed in Table 3 of the Emergency Identification and Response Action section in the Emergency and Remedial Response Plan.

The well completion design calls for the surface casing to be set to the top of the [redacted], below the lowermost USDW. Surface casing will be cemented to surface to prevent the movement of fluids into or between USDW's. Cement integrity will be verified by running a Cement Bond Log.

The long string casing for each well will be set to a depth of approximately 9,800 through all confining layers and injection zones. Cement will be circulated to surface. Cement integrity will be verified by running a Cement Bond Log.

Materials meeting ASTM standards were selected for well construction at this site and were chosen specifically because of their resistance to the effects occurred during exposure to a CO_2 stream and related fluids. Detailed information regarding construction materials is located in section 6.4 of the Testing and Monitoring Plan.

5.3 Casing and Cementing

Well construction materials meet existing industry standards and were selected using ASTM standards and due to their strength and structural characteristics for this case-specific application and to satisfy 40 CFR 146.86(b)(iv). The selected construction materials are designed to withstand downhole conditions such as corrosion, thermal fluctuations, pressures and exposure to formation fluids and the injection stream. Any indication of impacts to structural strength of materials used in the well construction during injection operations will be monitored through implementation of corrosion monitoring at the surface. Details are contained in section 6.4 in the "*Testing and Monitoring Plan"* which has been submitted in Module E – Project Plan Submissions.

Table 1 will provide casing depths and open hole diameters. Table 2 will provide the casing specifications. Table 3 will provide the proposed surface and long string cement programs. Tables 4 and 5 will provide the tubing and packer specifications. Figures 1, 2 and 3 provide a well schematic for the proposed [redacted] Injection well completions.

The following casing and cementing program will be applied to [redacted] injection wells. Conductor pipe will be the first string of casing set. The pipe is pile-driven from surface into the ground to a depth of approximately 80'. Each joint will be welded together as it is driven into the ground. The conductor pipe provides the initial stable structural foundation for a well to be drilled.

The surface casing will be set at approximately 2,650' and will be cemented in two stages. From a casing depth of 2,150' to 2,650', the casing will be cemented with 621 sacks of Class H cement with additives. From 2,150' to surface, the casing string will be cemented with 1,546 sacks of Class H/POZ cement with additives. To ensure that cement is circulated to surface, the volume of cement used includes 100% excess.

The long string casing will be set at TD (9,800') for all six injection wells and will be cemented in two stages. The upper portion of the long string from 0 to 3,700' will be cemented using 637 sacks of NeoCem ™ Cement or 50/50 Class H/POZ cement w/2 lbs/sk Pheno Seal Medium. Neo Cem™ cement is a low-Portland cement system that delivers high-performance compressive strength, elasticity, and shear bond at a lower density than conventional cement systems. The Neo Cem™ cement system is the first low-Portland oilfield cement system capable of improving the integrity of the hydraulic annular seal as well as the set-sheath elasticity. The benefits of the Neo Cem™ system is to help manage equivalent circulating densities with a lower-density system while retaining key performance parameters and to achieve barrier properties that help withstand the downhole dynamic demands from continual pressure and temperature changes throughout the life of a well. Poz or Pozzolan Ash replaces the cement and is CO2 resistant. Pheno Seal Medium is an additive that helps with loss circulation and is made up primarily of formica. The lower portion of the long string casing from 3,700 to T.D. (9,800') will require 2,060 sacks of CO_2 resistant cement. Halliburton's version of this slurry is named SBM CEM SHALECEM™ Sys w/0.25% HR-7 additive. The cement is made up of 50/50 Class H/Poz and/or Neo Cem TM discussed above plus a Latex 3000™ additive. The Latex 3000™ cement additive is a liquid additive designed to lower equivalent circulating density (ECD) and impart excellent fluid-loss control, high-temperature suspension properties and reinforces acid resistance to cement slurries and is used in both primary casing cementing operations and remedial squeeze work. These two cement blends have been successfully used for many decades in tertiary CO2 floods across West Texas, New Mexico and the Gulf Coast Area including the tertiary CO2 flood at Lockhart Crossing in Louisiana. Lockhart Crossing is a tertiary CO2 flood that injects CO2 in the Wilcox reservoir to recover additional oil that would be stranded in the reservoir. The Wilcox reservoir is also one of the two targeted storage intervals. The additive 0.25% HR-7 is a retarder and is made up of sodium lignosulfonate. Small amounts of HR-7 retarder can extend a slurry's temperature range and yield a smoother, more uniform slurry. In addition, HR-7 can provide extended pumping times, early cement-strength development, more predictable thickening times and improve slurry displacement rates at steady pressure. The long string cement volume is calculated including 35% excess cement in the open hole interval to ensure that cement is circulated to surface. In case cement is not circulated to surface, a DV tool is placed within the long string casing interval. If cement is not circulated to surface, the DV tool will be opened and excess cement in the casing and open hole annuli will be circulated out to surface. A new batch of cement volumes from the DV tool to the surface will be calculated and increased excess cement added. The new volume of cement will then be pumped down the long string, out the DV tool and circulated to surface.

Cement bond, variable density and temperature logs will be run for both the surface casing and the long string casing. Details on the logging program are contained in the "*Pre-Operational Logging and Testing Plan*" submitted in Module D - Pre-Operational Testing. Expected downhole temperature at total depth is 201 °F at 9,800 feet, which is not considered detrimental to the cement. The cement will increase in hardness over time and reach a value close to its maximum compressive strength soon after setting. In addition, a pressure fall-off test will be conducted to ensure that the well is completed as designed and that there is no opportunity for fluid migration into USDWs as a result of injection. Prior to running the tubing in the hole, each string will be visually inspected and drifted to ensure that no defects are present. The connections will be cleaned, and the manufacturer's recommended thread compound will be applied to the pin of each connection before make-up. Each connection of the injection tubing will be externally pressure tested to ensure no leaks exist upon makeup.

Injection packers will also be visually inspected to ensure no defects are present. A pressure test of the annulus will be conducted during installation of the packer to confirm proper setting and absence of leaks. The annular fluid designed for these wells is 9.0 lb/gal (1.08 Sp. Gr.) sodium chloride brine with inhibitors or equivalent. An annulus monitoring and pressurization system will always maintain the annulus at least 100 psi pressure greater than the injection tubing pressure (Figure 4) is an example of the proposed wellhead and Christmas tree for an injection well and will be used on all 6 wells. The wellhead is a general term used to describe the component at the surface of an oil and gas well that provides the structural and pressure containing interface for production equipment. The primary purpose of a wellhead is to provide the suspension point and pressure seals for the casing strings. The Christmas tree is installed on top of the wellhead and is a set of valves, spools, and fittings used to control the well fluids during production. All flow-wetted parts of both the wellhead and Christmas tree will be made of CO_2 resistant material.

5.4 Well Construction Details

Tables 1 through 5 provide the casing and cement programs for the injection wells. Injection wells will be constructed to meet the requirements of 40 CFR 146.86. This includes strategies to prevent the movement of fluids into or between USDWs, be constructed to permit the use of downhole tools and workover equipment. Wells will also be constructed using materials meeting ASTM standards and where necessary be constructed using CO_2 resistant materials. During construction both the surface and long string casing will be cemented to surface. This will be followed by running a cement bond log to verify integrity. The last step in well construction will be to perform mechanical integrity tests on each constructed injection well. Construction rules and details are shown in Table 6.

Details pertaining to equipment used in monitoring injection operations of the well(s) is described in the QASP as an attachment to the "*Testing and Monitoring Plan*". Emergency events and shut-off procedures are described in the "*Emergency and Remedial Response Plan*". Both of these plans are contained in Module E – Project Plan Submissions.

Table 5.1. Casing Depths and Open Hole Diameters

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Conductor	0 – 80	N/A	Driven
Surface	0 – 2,650	17 1/2	Set below USDW
Long-string	0 – 9,800	12 1/4	To total depth (TD)

Table 5.2. Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbs/ft)	Grade (API)	Design Coupling	Thermal Conductivity BTU/ft.hr deg F)
Conductor	0-80	20	19	94	X-42/X-52	Welded	31
Surface	0-2,650	13 3/8	12.515	61	J-55	Buttress	31
Long String	0-9,800	9 5/8	8.681	47	L-80	LTC	31

Name	Collapse Strength (psi	Biaxial Effect Collapse, Safety Factor	Joint Yield Strength (lbs/ft)	Body Yield Strength (lbs/ft)	Biaxial effect, Tensile Load, Safety Factor	Burst Strength (psi)	Biaxial Effect Burst, Safety Factor
Conductor	-	-	-	-	-	-	-
Surface	1,540	2.44	1,025,000	962,000	>15	3,090	4.99
Long String	7,100	>15	1,122,000	1,086,000	>15	6,870	>15

Table 5.3. Proposed Surface and Long String Cement Programs

Name	Openhole Diameter (inches)	Cement Stage	Type Cement	Depth (feet)	Density (ppg)	Excess (%)	Capacity (ft3/ft)	Yield (ft³/sack)	Sacks	Volume (bbl)
Surface	17 1/2	Lead	ECONOCEM ™ System w/0.2% HR-7	0-2,150	12.7	100	2986.9	1.932	1,546	532
Surface	17 1/2	Tail	HALCEM ™ System w/ 0.1% HR-7	2,150-2,650	15.6	100	694.6	1.179	589	124
Surface - Shoe Jt	Inside Casing	Tail	HALCEM ™ System	2,605-2,650	15.6	0	38.4	1.179	32	7
Long String	Inside Casing	Lead	Neo Cem™ w2lb/sk Pheno Seal Medium	0-2,650	12.0	0	924.8	2.149	430	165
Long String	12 1/4	Lead	Neo Cem™ w2lb/sk Pheno Seal Medium	2,650-3,700	12.0	0	443.9	2.149	207	79
Long String	12 1/4	Tail	SBM CEM SHALECEM™ Sys w/0.25% HR-7	3,700-9,800	14.5	35	2579.1	1.261	2055	459
Long String - Shoe Jt	Inside Casing	Tail	SBM CEM SHALECEM™ Sys w/0.25% HR-7	9,755-9,800	14.5	0	18.5	1.261	15	3

Table 5.4. Tubing Specifications

Name	Packer Setting Depth	OD (inches)	ID (inches)	Weight (lbs/ft)	Grade (API)	Internal Coating	Design Coupling	Burst Strength (psi)	Collapse Strength (psi)	Joint Yield Strength (lbs/ft)
4-1/2" tubing	75 feet above injection zone	4.5	3.958	12.75	L-80	Internal Coated with CO2 Resistant Material	Premium Connection	8,430	7,500	288,000

Table 5.5. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet)	Length (feet)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
9 5/8" x 4 1/2" Permanent Packer - Carbon Steel (L-80) body w/ Stainless Steel inner mandrel (wet area - 13Cr L80)	Within 75feet of top of perf	8.52	47	8.125	4.75

Tensile Rating (kbls)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
489	9,295	8,081	8.681	8.525

Table 5.6. Summary of Construction Details

CFR Rule	Details
40 CFR 146.86(a) 1-3	Well construction will prevent the movement of fluids between or into USDWs, permit the use of downhole tools and work over equipment, and permit continuous monitoring of the annulus between the casing and injection tubing
40 CFR 146.86(b) 1-3	Casing and cement used in the construction of the well will meet structural requirements, be constructed with materials meeting ASTM standards, and details of construction and depths for wells are shown in Figures 1 through 3.
40 CFR 146.86(b) 4 and 5	Surface and long string casing will be cemented to surface and verified with a cement bond log. Cement used for the long string casing will be CO_2 resistant, tubing and packer materials will meet ASTM standards. Characteristics of the CO_2 stream are detailed in the Testing and Monitoring Plan, and injection operation parameters are located in the Well Operations section in Project Information Tracking

5.5 Well Construction Diagrams

Well construction diagrams for each of the injection zones and wellhead schematic is shown in the following page(s).

Figure 1 Injection Well Diagram for [redacted] Injection Wells

[redacted]

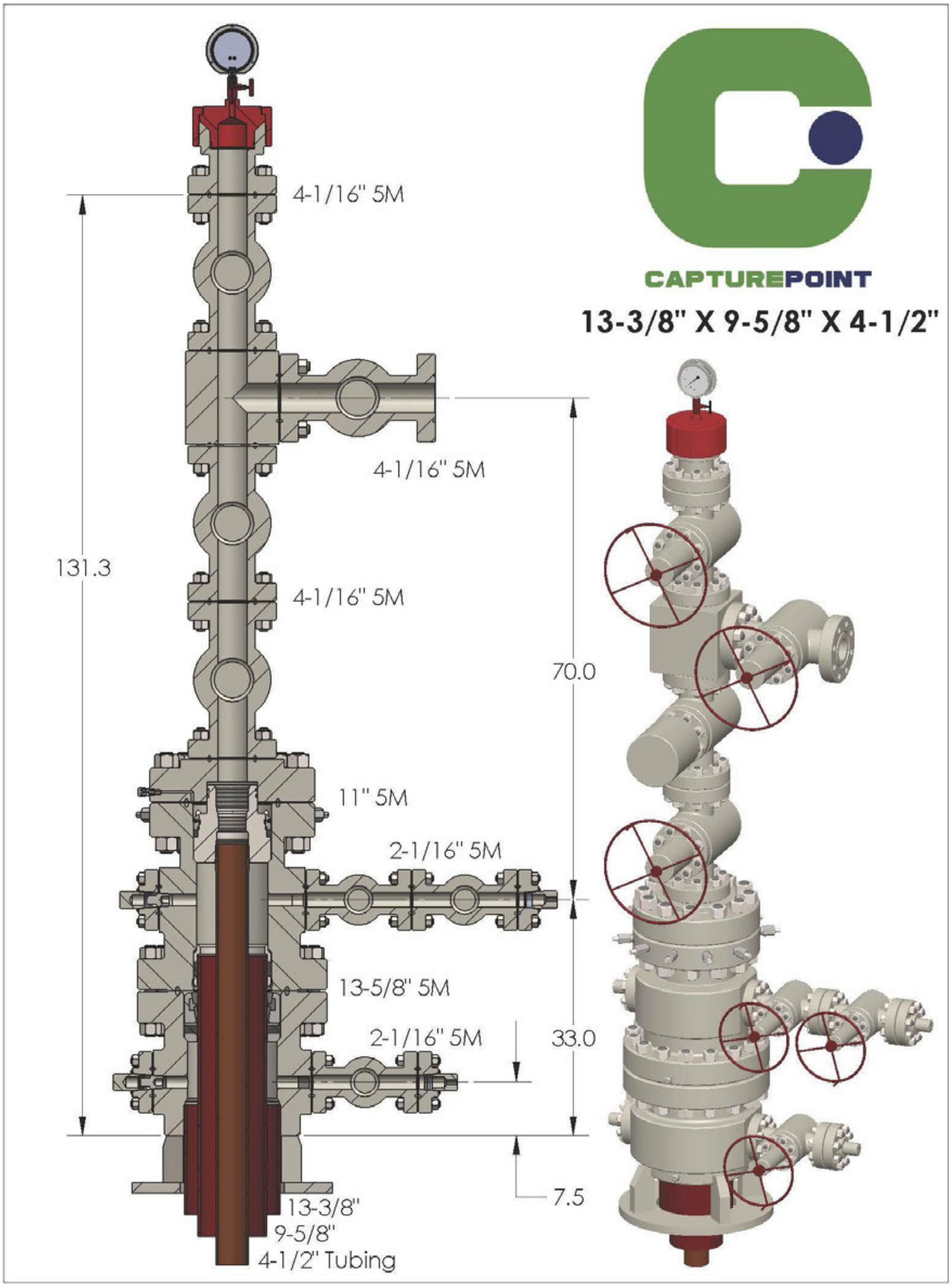
Figure 2 Injection Well Diagram for [redacted] Injection Wells

[redacted]

Figure 3 Injection Well Diagram for [redacted] Injection Wells

[redacted]

Figure 4. Wellhead and Christmas Tree Schematic



6.0 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

In each well, reservoir formation properties and individual well perforations will be determined by open hole log analysis and utilizing offset core and open hole logging data. The injection intervals selected are expected to have favorable reservoir characteristics that should not limit proposed injection targets. However, upon initial completion, it is expected to perform a low volume weak acetic acid matrix stimulation to clean the perforation tunnels, ensure all perforations are open and to remove any damage near well bore caused during the drilling and completion of the well. Per 40 CFR 146.91(d)(2), we are notifying the director of the intent to perform this type of stimulation to the well.

6.1 Introduction/Purpose

40 CFR 146 82(a)(9) requires the stimulation program, a description of the stimulation's fluids and a determination that stimulation will not interfere with containment. It is proposed to perform a weak acetic acid matrix stimulation to clean the perforation tunnels, ensure all perforations are open and to remove any damage near wellbore caused during the drilling and completion of the well. A low volume, weak acid matrix acidizing stimulation procedure is planned to accomplish this goal. Matrix acidizing refers to one of the two stimulation processes in which acid is injected into the well penetrating the rock pores at pressures below fracture pressure. As an additional safety factor, we will pump at a maximum treating pressure of 80 percent of the calculated fracture pressure. Following the matrix acid stimulation procedure an injection survey will be used to ensure that the stimulation did not interfere with containment.

6.2 Stimulation Fluids

80 percent Acetic acid

6.3 Additives

Not applicable at this time

6.4 Diverters

Not applicable at this time

6.5 Stimulation Procedures

In order to meet the requirements of 40 CFR 146 82(a)(9) please find the procedure to perform a weak and low volume acetic acid stimulation procedure on each interval perforated within a well.

- Acetic acid will be used based upon 10 gallons per 1 foot of perforation. For 300 feet of perforations assumed in this procedure 3,000 gallons of acetic acid will be used.
- The fractur pressure of each zone will be determined by core analysis and/or Step Rate Tests. The fracture pressure will not be exceeded.
- Coiled tubing will be used to spot the acetic acid across the perforation intervals.

- An injection survey will be run to verify containment within injection interval.
- The well has been perforated based upon openhole log evaluation and prior to rigging up coiled tubing to perform procedure. Assume a 300 foot perforated interval for volumes and rates. This will be adjusted based upon actual perforations.

Coiled tubing perforation cleanup matrix acidizing procedure

1. MIRU 2-3/8" coiled tubing. Spot acetic acid tanks. Hook up choke and blow down line.
2. RIH slowly through tree to make sure BHA clears. Begin rolling over pumps at approximately 0.25 BPM while maintaining shut in wellhead pressure on the choke.
3. Once 30 feet below wellhead, pick up speed to 100 feet per minute while continuing to circulate 0.25 BPM.
4. Stop 10 feet below perforated interval. Bring pump rate up to 2 barrels per minute and switch to pre-mixed acetic acid blend. Pump 3,000 gallons of acetic acid blend then switch to fresh water.
5. With 3 barrels before acetic acid blend reaches top perf, start POOH at 8.5 feet per minute. Pump acid blend across perforations at 10gal/ft. After all, 3,000 gallons have been displaced through coiled tubing, start pulling out of hole at 100 feet per minute.
6. Once on surface, shut in well. Begin rigging down coiled tubing unit.
7. Displace 3.0 volumes of 9-5/8" 47 #/ft, L-80 casing perforated volumes or 3.0 X 0.0732 barrels/feet X 300 feet = 65 barrels treated fresh water. Pump at a rate of 2 BPM at a maximum pressure of 80 percent of the calculated frac pressure.
8. Leave well shut–in overnight.
9. MIRU wireline unit. Run injection profile log including temperature surveys to evaluate containment of injection fluids. Rig down wireline
10. Report results and supply all profile logs to appropriate regulatory authorities.

7.0 Pre-Operational Logging and Testing

A stratigraphic test well will be drilled into the lowest targeted injection zone. This well will be drilled, cored, fluid samples collected, logged and tested to obtain the necessary information as it pertains to both the confining zone and for each of the three injection zones per the noted rules detailed in **Table 4**.

Upon completion, this well will be constructed as an in-zone monitoring well fitted with DTS/DAS fiberoptic sensors to monitor in-situ changes in temperature and pressure. The drilling and construction of the planned injection wells will require logging and testing of the aforementioned zones.

There are to be four intervals that are cored, these include core samples from the [redacted] (confining zone) and [redacted] (uppermost injection zone), the [redacted] (middle injection zone) and the upper portion of the [redacted] (lower most injection zone). Collected core will be analyzed and used to determine porosity, permeability, saturation and thickness. Fluid samples that are to be collected will be used to assess compatibility with the injected CO_2 and will comprise salinity, specific conductance and temperature. The compilation of geophysical log suites that are to be generated will be used to determine porosity, permeability and lithology for the zones of interest. Well tests that are to be performed will include a step-rate test for determining injection zone fracture pressure, operational injection pressure and a pump/injectivity test to determine operational injection rates and volumes for each of the three injection zones.

Prior to injection mechanical integrity tests (MITs) will be performed on each well to verify that mechanical integrity is sound and that there is no risk of endangerment to safety, USDWs or the environment.

Table 7.1. Summary of Data Components and Applicable Rules

Data Component	Rule Reference
Well logs	40 CFR 146.86(a)(2) 40 CFR 146.87 40 CFR 146.87(e)(1)
Cores	40 CFR 146.87(b) 40 CFR 146.82(a)
Fluids	
Well MIT	40 CFR 146.89(a)(1) 40 CFR 146.87(a)(4) 40 CFR 146.87(e)(1)
Formation characteristics	40 CFR 146.82(a)(8) 40 CFR 146.87(b) 40 CFR 146.87(c) 40 CFR 146.87(d)(1)

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing
Tab(s): Welcome tab
Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

8.0 Well Operation

Injection wells will be equipped with continuous pressure, temperature and rate monitoring equipment as well as physically monitored on a daily basis. As a consequence, the operation of wellhead and site valves will not be operated on any regular basis. Only in the event of a compression or supply issue, or scheduled testing will the wells be shut-in from injection. Rate and pressure limits are specified in Tables 5,6 and 7. On shut-in condition, valves should be closed in order from downstream to upstream and reversed on restart of injection. In all cases caution should be taken to avoid the condition of trapped gas between valves at the surface.

The Rapides One CCS Site is a proposed gas storage project that is targeting the [redacted] zones for CO_2 injection. CO_2 will be injected into each zone using two wells resulting in a total of [redacted] injection wells for the project. Injection into the targeted storage zones will occur at pressures that are not to exceed 90 percent of the determined fracture pressure. Injection rates for the three different injection zones are as follows 1) [redacted] ([redacted]) 2) [redacted] ([redacted]) and 3) [redacted]. Additional Well Operation information is detailed **in Section 2.9 Tables 22, 23** and **24** and **26, 27** and **28** in the "*AoR and Corrective Action Plan*" submitted in **Module B**. Operational parameters for the 3 named zones are also detailed below in **Tables 5, 6** and **7**.

8.1 Operational Procedures [40 CFR 146.82(a)(10)]

Operational procedures for the Rapides One CCS site are to be determined based on formation properties such as fracture pressure and injectivity. A site characterization well will be drilled and provide the necessary information as to provide for a more comprehensive update to the preliminary AoR model and injection simulation for the targeted injection zones. Calculations, assumptions and input parameters for the preliminary AoR modeling and simulation are described in the "*AoR and Corrective Action Plan*" submitted in **Module B**. Additional formation data will be collected with each injection well that is drilled at the site. Together the collected data and modeling and simulation will be used to determine Operational Procedures. These protocols are described in the "*Pre-Operational Testing Plan*" submitted in **Module D**. As part of the "*Pre-Operations Testing Plan*" submitted in **Module D** pursuant to 40 CFR 146.82(a)(8) and 146.87 a step rate test will be run in each well to confirm the fracture gradient and be used to determine injection pressure for the various layers.

Additionally, an injectivity test will be performed for each well to determine amenable volumes that can be injected. Together these formation tests will be used to refine the geologic model and to establish injection rates and volumes. During the operation phase of this sequestration project injection data regarding rates, volumes and temperatures will be continuously monitored per the "*Testing and Monitoring Plan*" submitted in **Module E**. This will include operating data for the targeted injection zones, average and maximum daily rates and volumes of the injected CO_2 stream and average and maximum daily injection pressures per 40 CFR 146.82. Injection data will be provided to the UIC Program Director in semi-annual reports.

The proposed key operating parameters are provided in Tables 5, 6 and 7 for each of the three injection zones. These were calculated based on the formula below. Further details are provided in Section 2.10 of "*AOR and Corrective Action Plan*" submitted in **Module B**.

Generalized Pressure Equations:

- Max Downhole Injection Pressure = $TVD_{fm} * F_g * 90\%$

- Max Injection Pressure (Surface) = Max Downhole Injection Pressure * TVD_{fm}* H_p * $SG_{CO2\ average}$

Where, TVD_{fm} = Injection zone true vertical depth

F_g = Fracture pressure gradient

H_p = Hydrostatic pressure gradient

$SG_{CO2\ average}$ = Average Injecting CO_2 Specific Gravity

The estimates of surface injection pressure which range from 1,940 to 2,900 psig in the Sparta to the Lower Wilcox do not take into account a specific wellbore thermal model nor the corresponding frictional losses. Initial injection testing on the wells will be analyzed to narrow the calculation accuracy.

Well tests for each injection well will occur once per year unless injection monitoring information indicate more frequent testing. Well work overs will also occur pending the results of continuous monitoring. Though not planned, it is likely that disruptions to the CO_2 supply will occur. These instances may occur as source providers may shut down for scheduled maintenance or because of other operational issues.

Near wellbore damage from salt and/or compressor oil deposition could degrade injectivity over time. In addition, reservoir back pressure could increase as the plume radius increases hence reducing injectivity. Although it should be minimal in these formations.

Table 8.1. Proposed [redacted] operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]		
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 8.2. Proposed [redacted] operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]		
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 8.3. Proposed [redacted] operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]		
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The plan for the proposed Rapides One CCS Site includes three targeted injection zones ([redacted]) with [redacted] injection wells per zone. For each of the zones we used the allowable reservoir pressure with a safety factor of 90% to arrive at the maximum injection pressure which is then used in the AoR model to arrive at the daily injection volumes.

As part of the "*Pre-Operations Testing and Logging Plan*" submitted in **Module D** pursuant to 40 CFR 146.82(a)(8) and 146.87 a step rate test will be run in each well to confirm the fracture gradient and be used to determine injection pressure for the various layers. Additionally, an injectivity test will be performed in the Sparta for each well to determine amenable volumes that can be injected. Together these formation tests will be used to refine the geologic model and to establish injection rates and volumes.

8.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

Sources of CO_2 for the Rapides One CCS site are described in Section 1. In summary sources will include industrial plants including fertilizer, ammonia and natural gas processing plants. CO_2 purity will be determined at the source of each industrial provider. CO_2 specifications for this gas storage project are noted in the "*Testing and Monitoring Plan*" submitted in **Module E**.

Characteristics of the CO_2 stream are described in Section 2.11 in the "*AoR and Corrective Action Plan*" submitted in **Module B**. Below are some excerpts from that section that describe the corrosive nature and likely behavior of CO_2 in the subsurface.

It is known that CO_2 and water will form Carbonic Acid (H_2CO_3) which in turn has the capability to dissolve calcium species in the formation. This can alter formation permeability and porosity depending on the native mineralogy. At the injection wellbore this can be an issue for well casing however, the dry dense phase CO_2 will continuously dry the area around the wellbore inhibiting any corrosion by absorbing the formation water and moving deeper into the formation.

The injected CO_2 at the Rapides One CCS site is expected to be soluble in water, which can provide a significant CO_2 trapping mechanism. This feature affects the reservoir by causing the higher density brine to sink within the formation thereby trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration.

Materials exposed to the CO_2 injection stream will be monitored throughout the injection phase of the project, methods of monitoring are also addressed in the "*Testing and Monitoring Plan*" submitted in **Module E**. All materials with exposure to the injection stream were selected based on their resistance to corrosion when exposed to CO_2 and CO_2-related fluids.

9.0 Testing and Monitoring

The Testing and Monitoring Plan Report has been submitted via the GSDT in 'Confidential Business Information' form. All tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the overall strategy and approach for testing and monitoring, carbon dioxide stream analysis, continuous recording of operational parameters, corrosion monitoring, above confining zone monitoring, external mechanical integrity testing, pressure fall off testing, carbon dioxide plume and pressure front tracking, environmental monitoring at the surface, sampling/analytical procedures. A Class IV well Quality Assurance and Surveillance Plan (QASP) was submitted as an appendix along with additional information relation to project management, data generation and acquisition, assessment and oversight and data validation and usability.

The Testing and Monitoring Plan Report satisfies rule requirements 40 CFR 146.82(a)(15) and 146.90.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

10.0 Injection Well Plugging

An Injection Well Plugging Plan has been developed and electronically submitted to the GSDT pursuant to 40 CFR 146.82(a)(16) and 146.92(b). The plan describes the materials that are to be used and includes a plugging schematic representative for all injection wells.

The Injection and Well Plugging Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the planned tests and measurements to determine the bottom hole reservoir pressure, Planned External Mechanical Integrity Test, Information on Plugs, methods used for volume calculations, notifications, permits and inspections required, plugging procedures and contingency procedures/measures. The Injection and Well Plugging Plan satisfies rule requirements 40 CFR 146.82(a)(16) and
146.92(b).

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

11.0 Post-Injection Site Care (PISC) and Site Closure

The Post Injection Site Care and Site Closure Plan (PISC) Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the pre and post injection pressure differential, post-injection monitoring plan, the post-injection site care timeframe, non-endangerment demonstration criteria, site closure plan and QASP.

The Post Injection Site Care and Site Closure Plan satisfies rule requirements 40 CFR 146.82(a)(17) and 146.93(a) and the Alternative PISC submission satisfies rule requirements 40 CFR 146.82(a)(18) and 146.93(c).

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

12.0 Emergency and Remedial Response

The Emergency and Remedial Response Plan has been submitted via the GSDT in 'Confidential Business Information' form. All Tabs that require input data within the module have also been completed and submitted via the GSDT. A 'Confidential Business Information' version has been submitted to Region VI of EPA as well.

The report covers in detail the local resources and infrastructure, potential risk scenarios, response personnel and equipment, emergency communications plan, a plan review and staff training and exercise procedures.

The Emergency and Remedial Response Plan Report satisfies rule requirements 40 CFR

146.82(a)(19) and 146.94(a).

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

13.0 Injection Depth Waiver and Aquifer Exemption Expansion

An injection depth waiver is not required for this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☒ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

14.0 Other Information

CapturePoint Solutions, LLC utilized the EJScreen: Environmental Justice Screening and Mapping Tool (Version 2.0) (https://ejscreen.epa.gov/mapper/) to identify issues with respect to the proposed Rapides One CCS Site. At this time no instances of the listed indexes in the tool were identified to be impacted or exacerbated by the proposed GS project. The nearest denoted index issues are identified to be located approximately [redacted] of the proposed site location and these all relate to the city of [redacted].

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