CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Project Name: Pineywoods CCS Hub

Facility Information

Facility Contact: Pineywoods CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

RRC Organization
Report Number: in process

Entrance Location: 30° 3'45.96"N, 94°33'14.78"W

Well Locations: Liberty and Hardin Counties, Texas

Well Name	Latitude (dms)	Longitude (dms)
PW-1	30° 2'1.24"N	94°31'16.30"W
PW-2	30° 3'45.96"N	94°33'14.78"W
PW-3	30° 6'7.27"N	94°31'27.22"W
PW-4	30° 7’58.94”N	94°31’28.79”W

Table of Contents

List of Figures

List of Tables

List of Definitions

Injection zone: stratigraphic units between the base of the primary confining zone and the top of the lower confining zone.

Injection interval: formation where CO_2 will be injected.

List of Acronyms

AOB-(#)	Above-Zone Observation Well – (#)
AOR	Area of Review
API	American Petroleum Institute
CCS	Carbon capture and storage
CO_2	Carbon dioxide
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
ft	Feet
GAU	Groundwater Advisory Unit of Texas
GR	Gamma ray
HPF	Hatters Pond Fault
IOB- (#)	In-Zone Observation Well – (#)
MASP	Maximum allowable surface pressure
MD	Measured depth
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
t	Metric tons
MMt	Million metric tons
t/d	Metric tons per day
t/y	Metric tons per year
MMt/y	Million metric tons per year
NMR	Nuclear Magnetic Resonance
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
PW	Pineywoods CCS Hub
PW-(#)	Pineywoods CCS Hub injection well number
RRC	Railroad Commission of Texas

RCA	Routine core analysis
SEM	Static Earth Model
SGR	Shale gouge ratio
SLB	Schlumberger
SS	Sub- Sea
TD	Total Depth
TVD	True Vertical Depth
TWDB	Texas Water Development Board
UIC	Underground Injection Control
UOB-(#)	Underground Source of Drinking Water Observation Well – (#)
USDW	Underground Source of Drinking Water
VME	Von Mises Stress

PROJECT BACKGROUND AND CONTACT INFORMATION

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)]***

A.1. Pineywoods CCS Hub

Pineywoods CCS, LLC, an affiliate of Tenaska, Inc. (Tenaska), is proposing development of an industrial scale carbon capture and storage (CCS) hub in Liberty and Hardin Counties, Texas (**Figure 1**). The Pineywoods CCS Hub ("the project") area is located between the towns of Daisetta, Texas (to the west) and Sour Lake, Texas (to the east) and additionally includes the northwest corner of Jefferson County. The Area of Review (AOR) covers approximately 70,400 acres (110 square miles).

Figure 1: Location of Pineywoods CCS Hub in Southeastern Texas.

The project is seeking to permit and drill up to four injection wells (PW-1, PW-2, PW-3 and PW-4), four in-zone observation wells (IPW-1, IPW-2, IPW-3, and IPW-4), three above-zone observation wells (AOB-1, AOB-2, and AOB-3), and six lowermost underground source of drinking water (USDW) observation wells (UOB-1, UB-2, UOB-3, UOB-4, UOB-5, and UOB-6). These wells will be drilled on 11 well pads. Up to seven shallow groundwater observation wells (not shown) will be drilled on existing well pads (locations to be determined). The location of each well pad and its associated injection and/or observation well is shown in **Figure 2**.

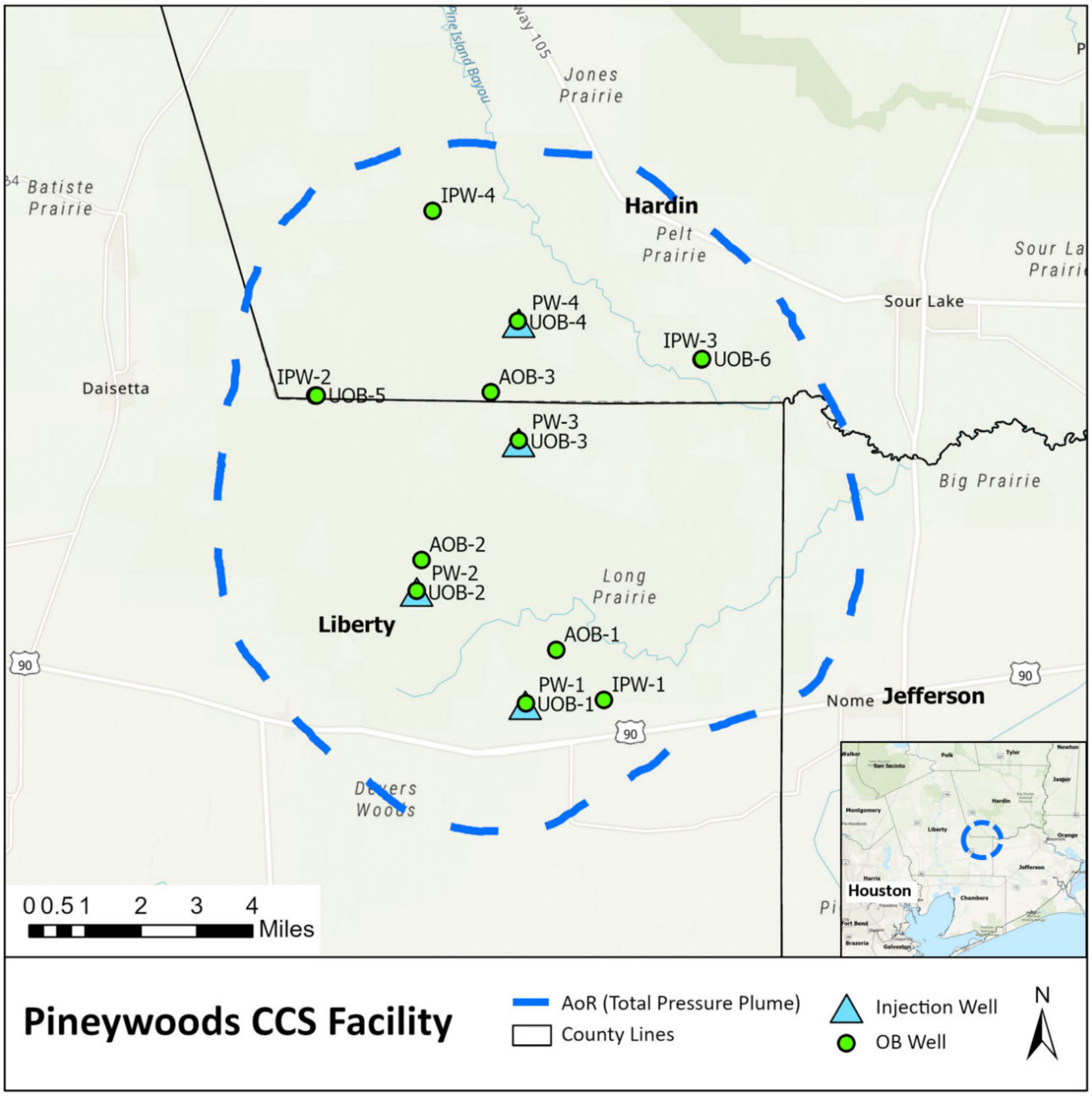

Figure 2: Map of the Pineywoods CCS Hub with the location of the proposed injection and observation wells and AOR.

To address all EPA and RRC regulatory requirements, two detailed maps of the Pineywoods CCS Hub were created. **Figure 3** and **Figure 4** show notable surface and subsurface features in and around the project area the location including surface bodies of water, city limits for the nearby cities, numerous roads, land containing buildings, protected areas, EPA cleanup sites, pipelines, all previously drilled wells and literature location of faults. No surface or subsurface mines, quarries, or tribal areas are in or near the Pineywoods CCS Hub. Locations of cathodic protection holes were not publicly available.

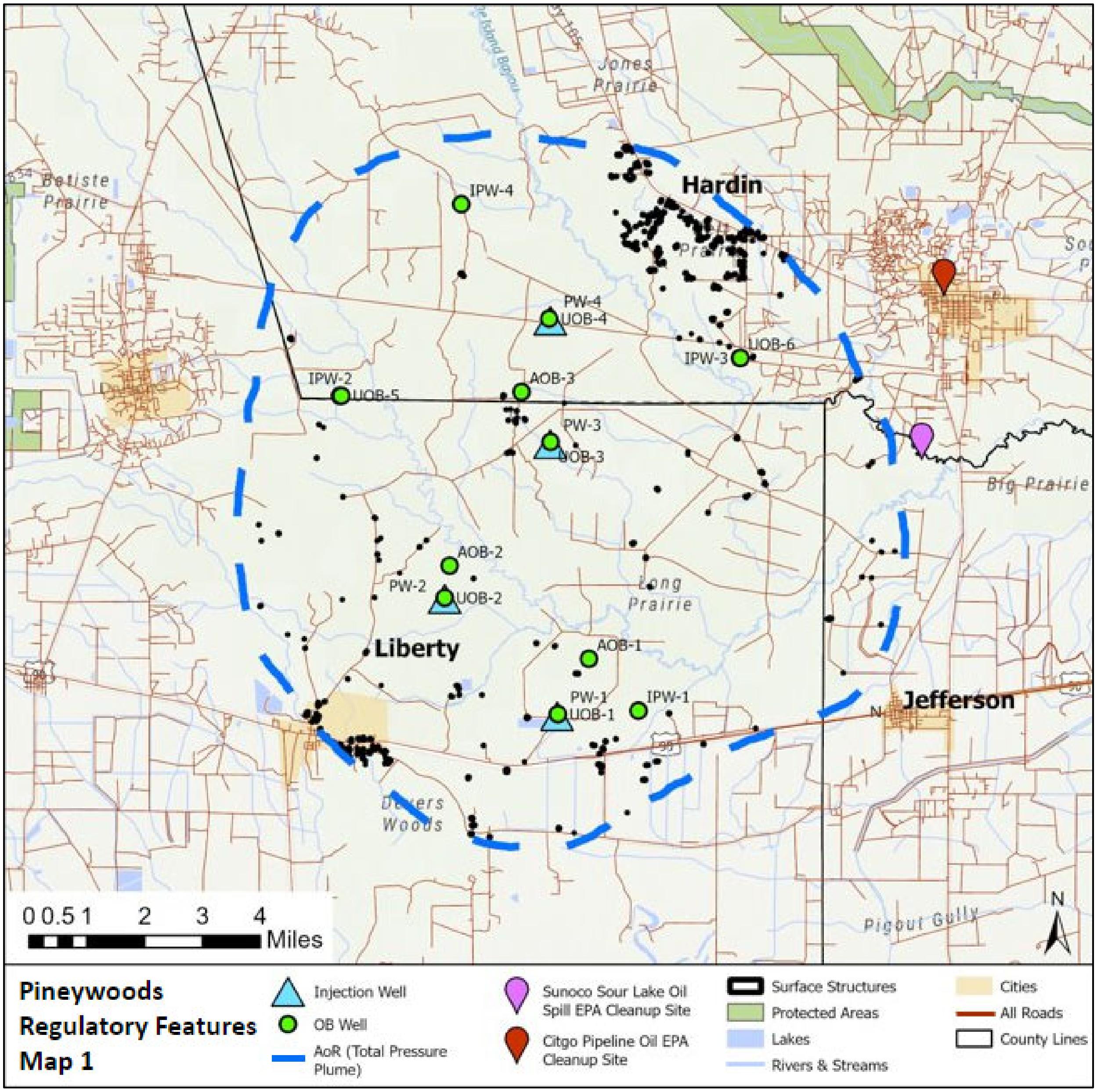

Figure 3: Surface feature map of the Pineywoods CCS Hub and its AOR. Surface structures, EPA sites, protected areas, surface water bodies and all roads are included to address regulatory requirements. Well spots with multiple symbols will have co-located wells on the same well pad.

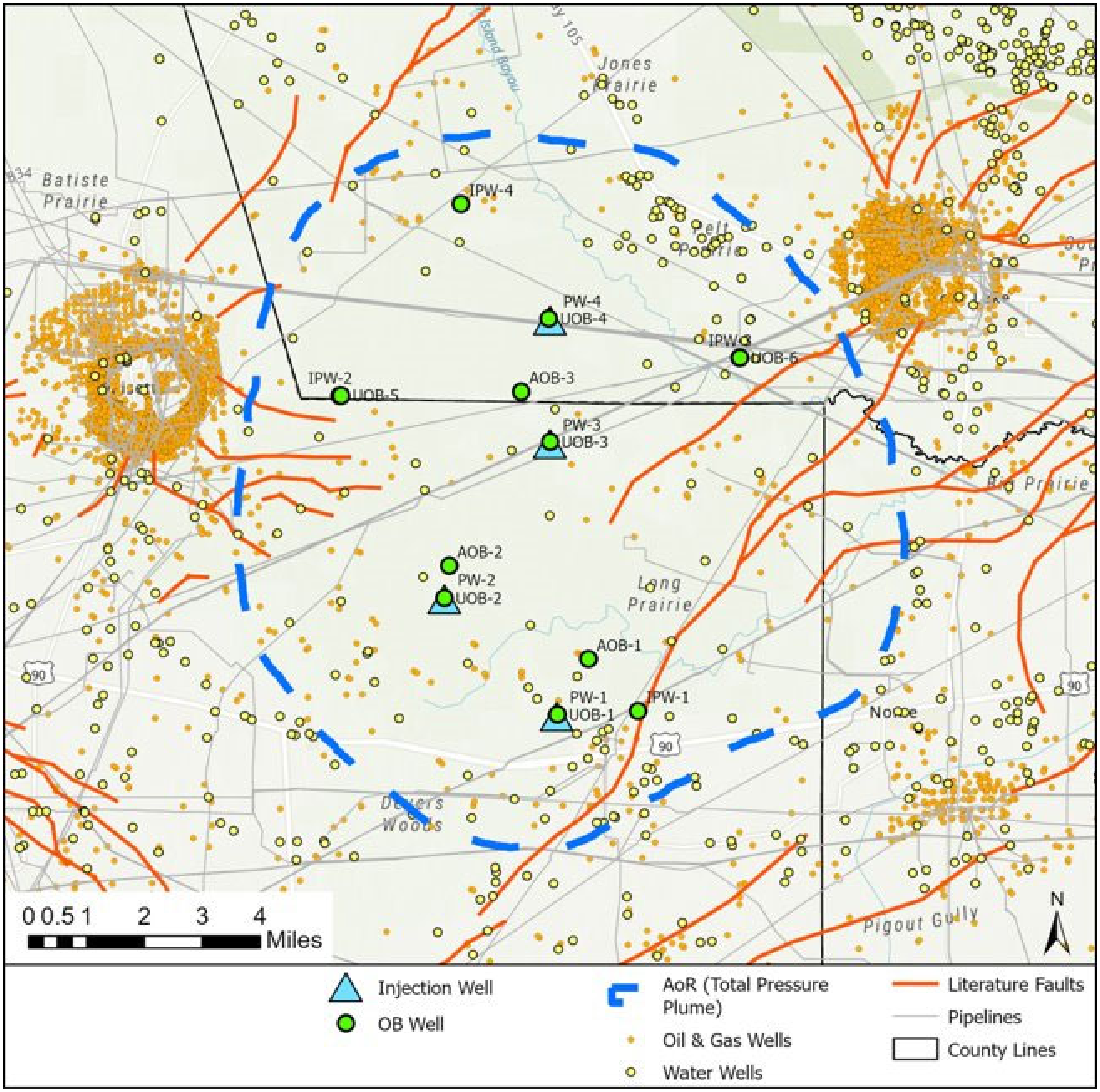

Figure 4: Subsurface feature map of the Pineywoods CCS Hub and its AOR. All oil and gas wells as well as water wells, literature faults, and pipelines are depicted to address regulatory requirements.

The area in and near the Pineywoods CCS Hub contains both shallow water supply wells and deeper wells related to oil and gas production and wastewater disposal. Within the AOR, there are 116 shallow water wells and 169 oil and gas wells. The well number, latitude, longitude, well type (i.e., public, domestic), and depth of the wells within the AOR are provided in **Appendix A of the**

Area of Review and Corrective Action Plan.

The subsurface within and around the AOR has been well studied. Battelle performed a preliminary site assessment for the Pineywoods CCS Hub prior to the preparation of this permit application. Much of this work was the result of the DOE-sponsored Frio Brine Pilot Project, where 1,600 tons of CO_2 was injected 1,500 m below surface into a high permeability brine-bearing sandstone of the Frio Formation beneath the Gulf Coast of Texas, USA (Hovorka, et al., 2005). This work has shown that the area has attractive geologic properties and large potential for safely and permanently storing CO_2 in the deep saline reservoirs below the project area.

No depth waiver or aquifer exemption is requested for the project since the proposed injection interval is more than 2,000 feet deeper than the deepest USDW in the area and the reservoir fluid in the proposed injection interval is highly saline, with total dissolved solids (TDS) greater than 113,000 mg/L.

Monitoring protocols have been designed to allow Pineywoods CCS, LLC to track the areal and vertical extent of the CO_2 plume, the development of the elevated pressure front, and changes in pressure, saturations, and fluid composition above the confining zone. These protocols will also provide input data to periodic reevaluation of the AOR through computational modeling of CO_2 plume and reservoir pressures as well as changes in above injection interval conditions to ensure containment of the injectant CO_2.

The Pineywoods CCS Hub will provide safe, secure, and long-term CO_2 storage for CO_2 emissions from key sources.

A.2. Proposed CO_2 Source and Mass/Volume of Injection.

Potential CO_2 sources are power plants, cogeneration plants, hydrogen production facilities, gas processing facilities, refineries, and petrochemical facilities near the Pineywoods CCS Hub. These sources could provide up to 18 MMt/y of CO_2 injection, though initial plans are to provide up to 5 MMt/y of CO_2 injection for 30 years (150 MMt total). The four injection wells will be capable of storing 13,900 t/d.

A.3. Project Scope and Timeframe

The four proposed injection wells will be permitted and drilled in the center of the Pineywoods CCS Hub with each well located approximately 2 to 3 miles apart in a north-south orientation. Computational reservoir modeling work shows that the four injection wells will be able to safely inject the proposed volume of CO_2 provided from the sources.

Pineywoods CCS, LLC will initiate injection upon receiving EPA approval for operation of the well. It is anticipated that the 30-year injection period will start in approximately 2025, end in 2055, and be followed by a proposed 20-year post-injection site care period, taking the project to 2075.

A.4. Partners/Collaborators/Stakeholders

Tenaska, Inc. (Tenaska) has made major, corporate-level commitments toward the development of the project. Tenaska is a privately held, independent power company based in Omaha, Nebraska. Established in 1987, Tenaska has a generating fleet over 7,500 MW, is one of the largest gas marketing companies in North America, and has balance sheet equity of $2.9 billion. Pineywoods CCS, LLC, an affiliate of Tenaska, will serve as the project owner and will assume liability for the project development, finance, and operation. The project will be conducted entirely within the State of Texas in Liberty and Hardin Counties. No tribal or territory boundaries will be impacted per 40 CFR 146.82(a)(20).

The key project contacts are:

Pineywoods CCS, LLC
Ryan Choquette, Sr. Project Manager
Tenaska, Inc.
14302 FNB Parkway
Omaha, Nebraska 68154
[redacted]

Advanced Resources International, Inc.
Michael L Godec, Vice President
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The key state contacts are:

Railroad Commission of Texas, Oil & Gas Division, Carbon Sequestration Group
Bryce McKee, P.G.
1701 N. Congress
Austin, Texas 78701
512-463-2259, bryce.mckee@rrc.texas.gov

Texas Commission on Environmental Quality
Underground Injection Control Permits Section
P.O. Box 13087
Austin, Texas 78711-3087
512-239-6466, uic@tceq.texas.gov

A.5. Other Permit Information Required Under 40 CFR 144.31(e)

Applicable SIC Codes

Per ***40 CFR 144.31(e)(3)***, the SIC codes applicable to the Pineywoods CCS Hub are:

1. 49530300 Nonhazardous waste disposal sites – primarily engaged in collection and disposal of refuse by processing or destruction or in operation of incinerators/waste treatment plants/landfills/other sites for disposal of such materials;
2. 51690203 Carbon Dioxide – primarily engaged in wholesale distribution of CO_2; and
3. 4619 Pipelines, not elsewhere classified – primarily engaged in pipeline transportation of commodities except petroleum and natural gas.

Permits and Authorizations

Per 40 CFR 144.31(e)(6), the permits and authorizations that will likely be required for the wells at the Pineywoods CCS Hub, the permit/authorization jurisdictions, and the associated project development activities are provided in **Table 1**.

Table 1: Permits and authorizations to be obtained for the development of the Pineywoods CCS Hub.

Permit/Authorization	Activity	Jurisdiction
UIC Class VI Injection Well Permit to Construct	Drilling of Injection Wells	Federal
UIC Class VI Injection Well Authorization to Inject	Injecting CO_2	Federal
Greenhouse Gas Rule Subpart RR Monitoring, Reporting, and Verification Plan Approval	Injecting CO_2	Federal
Section 404 Nationwide Permit	Temporary impacts to jurisdictional waters	Federal
Geologic Storage Facility Permit	Construction and operation of injection wells	Texas Railroad Commission
Permit to Drill, Deepen, or Convert a Well	Drilling of injection and observation wells	Texas Railroad Commission
TPDES Construction General Permit No. TXR150000	Management of stormwater during construction	Texas Commission on Environmental Quality
Commercial Development Permit	Any building 100 square feet or larger constructed or moved onto a property and to obtain electrical service	Liberty County

Permit/Authorization	Activity	Jurisdiction
Development Permit	Man-made change to improve real estate, including drilling operations	Hardin County

B. GEOLOGIC SITE CHARACTERIZATION

B.1. Regional Geologic Structure and Hydrogeologic Properties [40 CFR 146.82(a)(3)]

B.1.1 Data Used for Geologic Characterization

The data used to develop the geologic model of the Pineywoods CCS Hub includes drilled well information and two-dimensional (2D) seismic data. Drilled well information includes location, deviation surveys, well logs, hydrocarbon production, and wastewater injection rates. The well logs include: Measured Depth, Gamma Ray, Neutron Porosity Sandstone, Density Porosity Sandstone, Bulk Density, Spontaneous Potential, Caliper, Shallow, Medium and Deep Resistivity, and Sonic.

The Parker Estate 1 well served as the Type Log **(Figure 5)** for the primary upper confining unit and proposed injection interval. Geologic formation tops were then picked on all well logs. A synthetic seismogram was created to tie the seismic data to the well data. Geologic formations were then mapped on the 2D seismic data and structure and isopach maps were created using both the well log tops and 2D seismic data.

Tenaska licensed 97.43 linear miles of existing 2D seismic lines that transect the Pineywoods CCS Hub (**Figure 6**). This data was used to interpret site-specific and regional geologic structure, to determine lateral continuity, and build the geologic inputs used for computational modeling. The seismic data included nine lines that provided data to refine the structural interpretation of the Pineywoods CCS Hub. Additionally, seismic data was used to confirm the lateral continuity of the injection and confining zones.

During the synthetic seismogram creation, the 2D seismic lines were tied to sonic measurements taken in the Arco Fee #1 well (**Figure 7**) to correlate the structural interpretation of the Pineywoods CCS Hub to the porosity and permeability model developed using the well log data. Together, these data sets were used to build a 3D Static Earth Model (SEM) in the Petrel geological modeling software suite representative of the geologic and petrophysical characteristics within the Pineywoods CCS Hub (Petrel is trademarked by and licensed from Schlumberger (SLB) Corporation). The areal extent of the 3D SEM is shown in **Figure 8.**

To provide additional data on regional structure and stratigraphy surrounding the Pineywoods CCS Hub, 51 digital gramma ray/SP logs from legacy wells were acquired and loaded into SLB's Petrel geologic interpretation software. 49 of these logs covered the entire injection zone and primary confining unit. Well log cross sections, shown later in this application narrative, were created using a subset of these logs. Locations of these wells are shown in **Figure 8**.

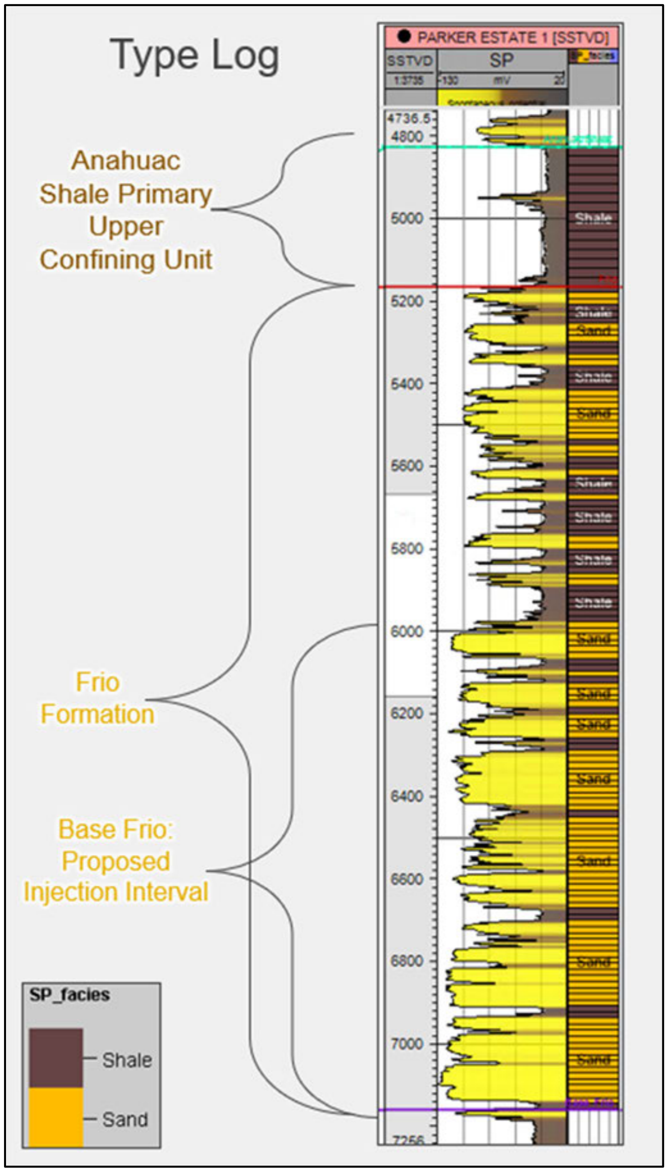

Figure 5: Type log from Parker Estate 1 well used for site-specific geologic characterization of the primary upper confining unit and proposed injection interval.

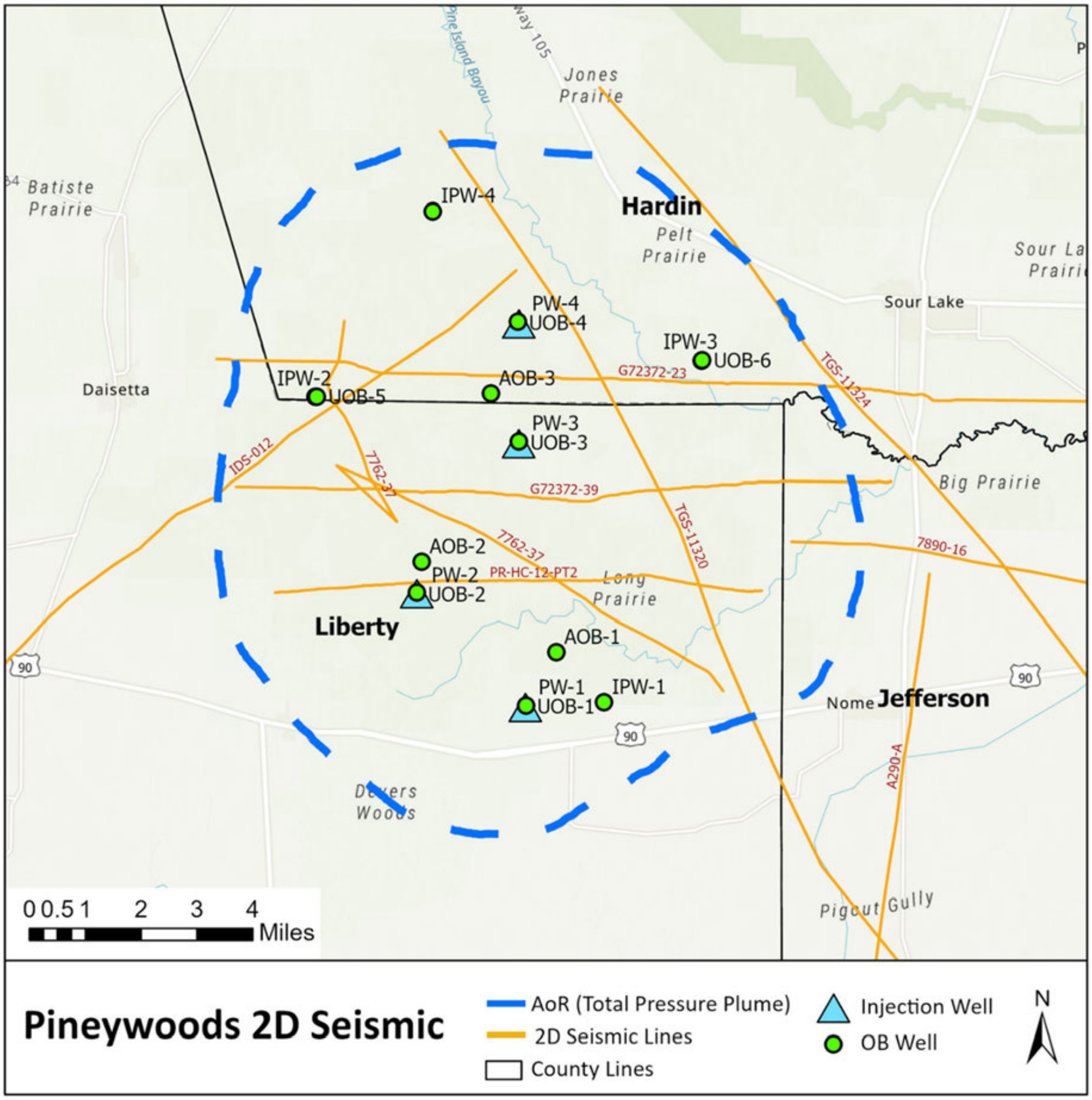

Figure 6: Map of the location and names of the nine 2D seismic lines interpreted for the geological model.

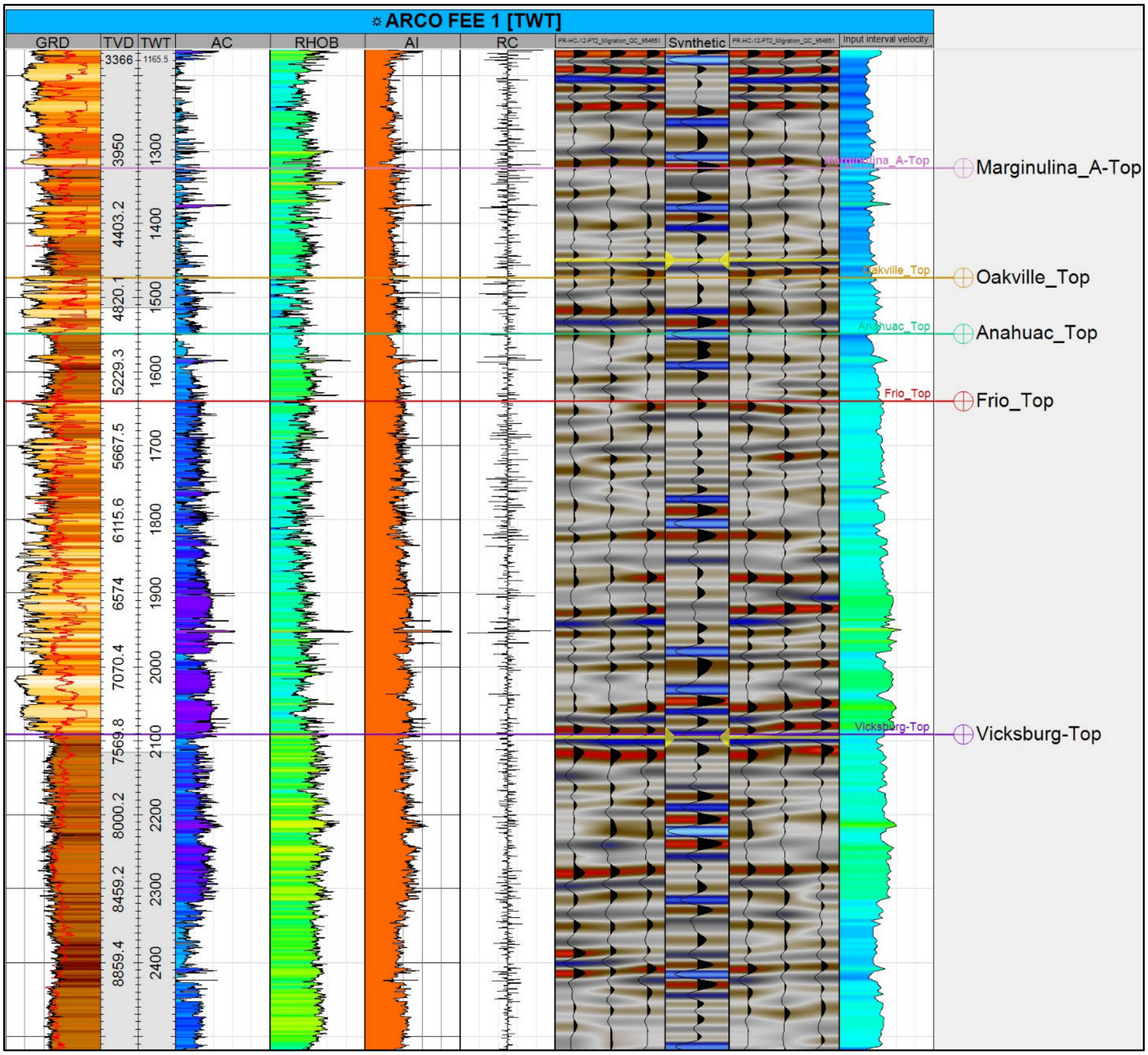

Figure 7: Synthetic seismogram created using logs from the Arco Fee 1 well to tie the 2D seismic data to the well logs.

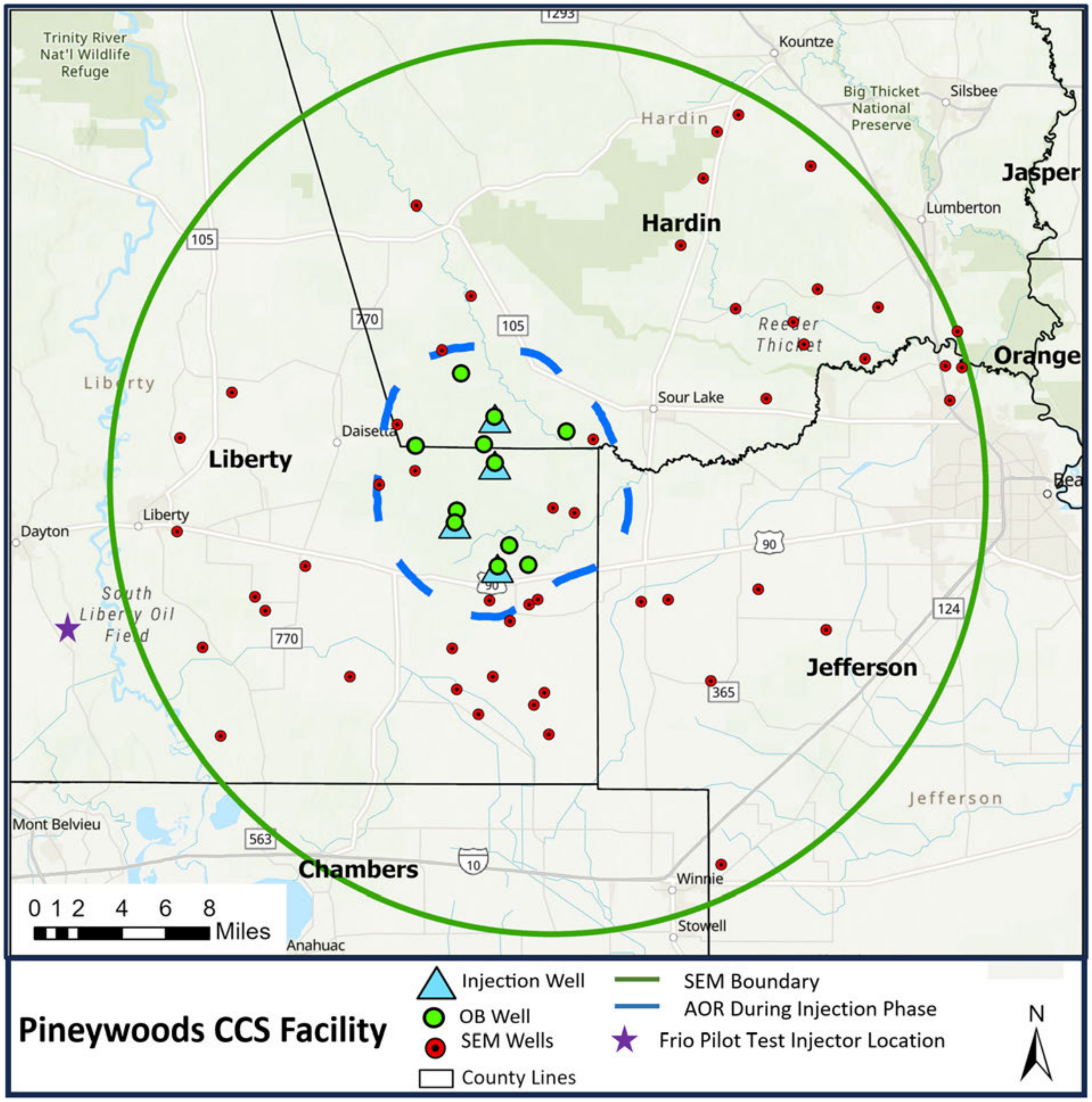

Figure 8: Aerial extent of Static Earth Model (SEM) for Pineywoods CCS Hub and location of wells used to generate the SEM.

B.2. Maps and Cross Sections of the Pineywoods CCS Hub Model Area [40 CFR 146.82(a)(3)(i)]

B.2.1. Stratigraphic Column of the Pineywoods CCS Hub

The initial CO_2 injection interval for the Pineywoods CCS Hub is the lower Oligocene Frio Formation. The Frio Formation contains a series of mostly thick sandstones and some interbedded shales divided into lower, middle, and upper units.

Based on well top picks and 2D seismic data, the Lower Frio Formation is located at approximately 6,000 to 7,100 ft SSTVD (6,074 to 7,174 ft below ground surface) within the Pineywoods CCS Hub (**Figure 9**). Average net sand thickness in the Lower Frio is approximately 585 ft and is distributed into 3 to 5 main sandstone units. The Frio Formation has favorable reservoir properties, such as its thickness, lateral continuity, and porosity to meet storage requirements, as further detailed in this **Section B** below and summarized in **Section B.10**. The top of the thick Vicksburg shale interval serves as the base of the storage interval at the Pineywoods CCS Hub.

The Upper Frio Formation serves as a minor saline reservoir with an average top at 5,200 ft SSTVD based on the SEM. The upper Frio is defined by three distinct sandstone layers, the “A”, “B”, and “C”, which contain intermittent shale layers and are separated by thin shale seals (McGuire, 2009).

Overlaying the Frio Formation is the nearly 400-ft thick Oligocene Anahuac Formation. The Anahuac shale serves as the primary upper confining unit with transgressive and thick marine shales to prevent the upward flow of formation fluids from the injection zone. This formation is regionally extensive and covers the Pineywoods CCS Hub.

The Anahuac Formation is overlain by Miocene interbedded sandstones, including the Upper, Middle, and Lower Miocene. The Middle Miocene, Lower Miocene 1, and Lower Miocene 2 are minor saline reservoirs while the Amphistegina-B and Marginuline-A would serve as confining units for these Miocene intervals if they are considered for CO_2 storage in the future and would provide secondary and tertiary seals for the Frio Formation.

In addition to the Anahuac shale and Miocene sandstones, the injection interval is overlain by the Pliocene Willis, Pleistocene Lissie, and Beaumont Formations towards the surface. In total, about 3,900 ft of strata separates the top of the CO_2 injection interval in the Frio Formation at 6,000 ft. and the deepest USDW, located at a depth of approximately 2,100 ft inside the Evangeline Aquifer. (**Figure 9**). These formations are further described in **Table 2**.

System	Series	Stratigraphic Unit	Aquifers, Reservoirs and Confining Zones	Depths (SSTVD)
Tertiary	Pliocene	Undifferentiated	Chicot Freshwater Aquifer	
	Miocene	Upper Miocene	Evangeline Freshwater Aquifer	Lowermost USDW Base at ~2,100'
		Middle Miocene	Minor Saline Reservoir	
		Amphistegina B	Confining Unit	
		Lower Miocene 2	Minor Saline Reservoir	
		Marginuline A	Confining Unit	
		Lower Miocene 1	Minor Saline Reservoir	
	Oligocene	Anahuac Formation (shale)	Primary Upper Confining Unit	Top at 4,810'
		Upper Frio Formation (interbedded shales)	Minor Saline Reservoir	Top at 5,200'
		Lower Frio Formation (mostly sands)	Primary Saline Reservoir: Proposed Injection Zone	Top at 6,000' Base at 7,100'
		Vicksburg Formation	Primary Lower Confining Unit	

Figure 9: Generalized stratigraphic column identifying the storage reservoir, confining zones, and the deepest USDW addressed in this permit for the Pineywoods CCS Hub.

Table 2: Formations comprising the Pineywoods CCS Hub

Regulatory Interval	Formation Name	Expected Depth Interval (ft subsea)
Primary Confining Zone	Anahuac	4,810-5,200
Potential Injection Interval	Upper Frio	5,200-6,000
Primary Injection Interval	Lower Frio	6,000-7,100

B.2.2. Regional Structural Setting of the Pineywoods CCS Hub

The Pineywoods CCS Hub is located within the Houston Embayment Salt Basin **(Figure 10)**. The area experiences local and regional faulting. Structural deformation in the Gulf Coast is primarily driven by the presence and movement of the Louann salt as well as gravity-related tectonic elements such as normal growth faults (Hovorka et al., 2003).

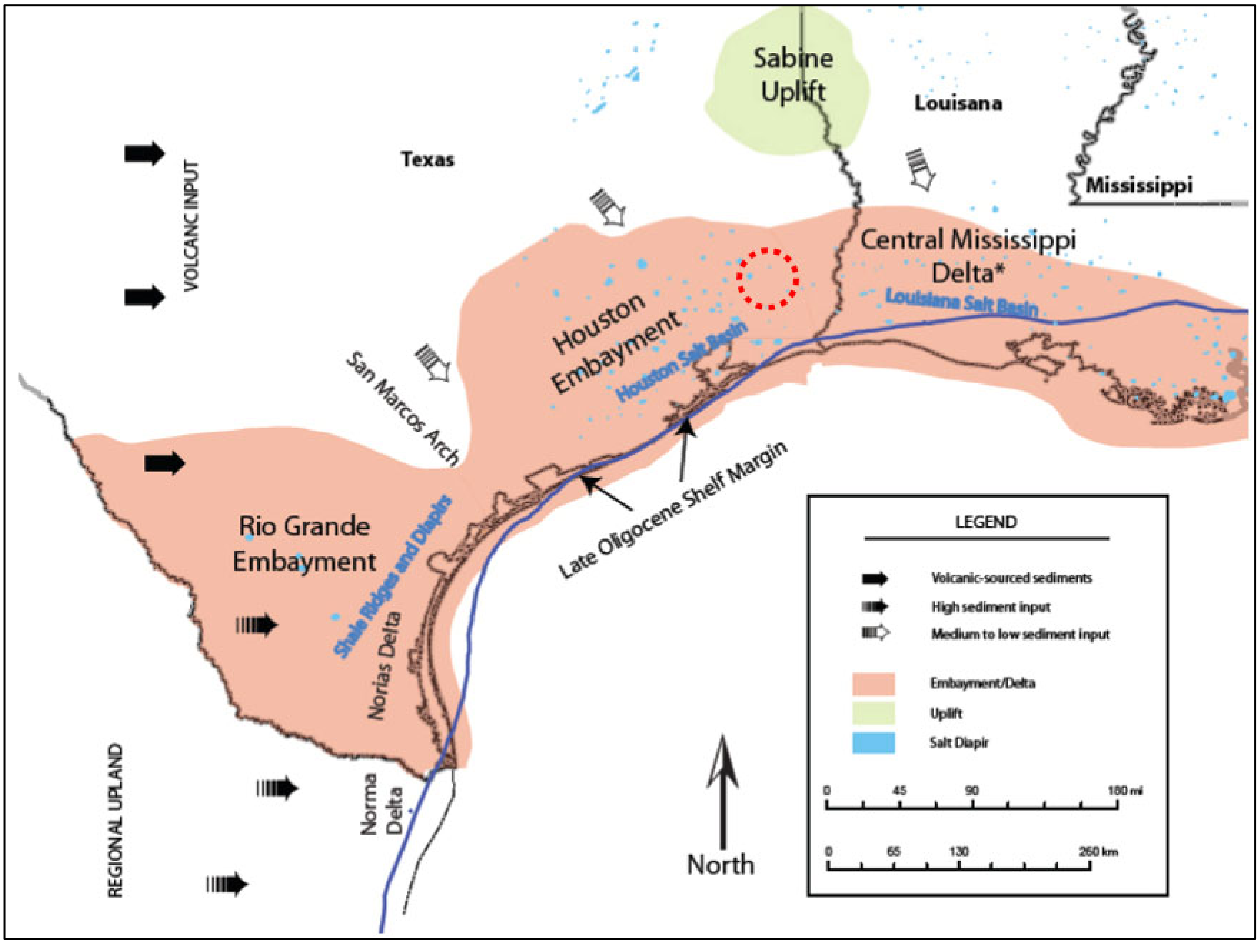

Figure 10: Regional setting of the Gulf of Mexico coastline during the late Oligocene showing the approximate study area in red dashed circle within the Houston Embayment (USGS, 2009).

The AOR is situated between two salt domes. The Daisetta salt dome to the west and the Sour Lake salt dome to the east **(Figure 11).** The injection wells are aligned in a north-south fashion to create a pressure plume between the salt domes and a maximum AOR that does not intersect either salt dome or existing hydrocarbon well penetrations **(Figure 11).**

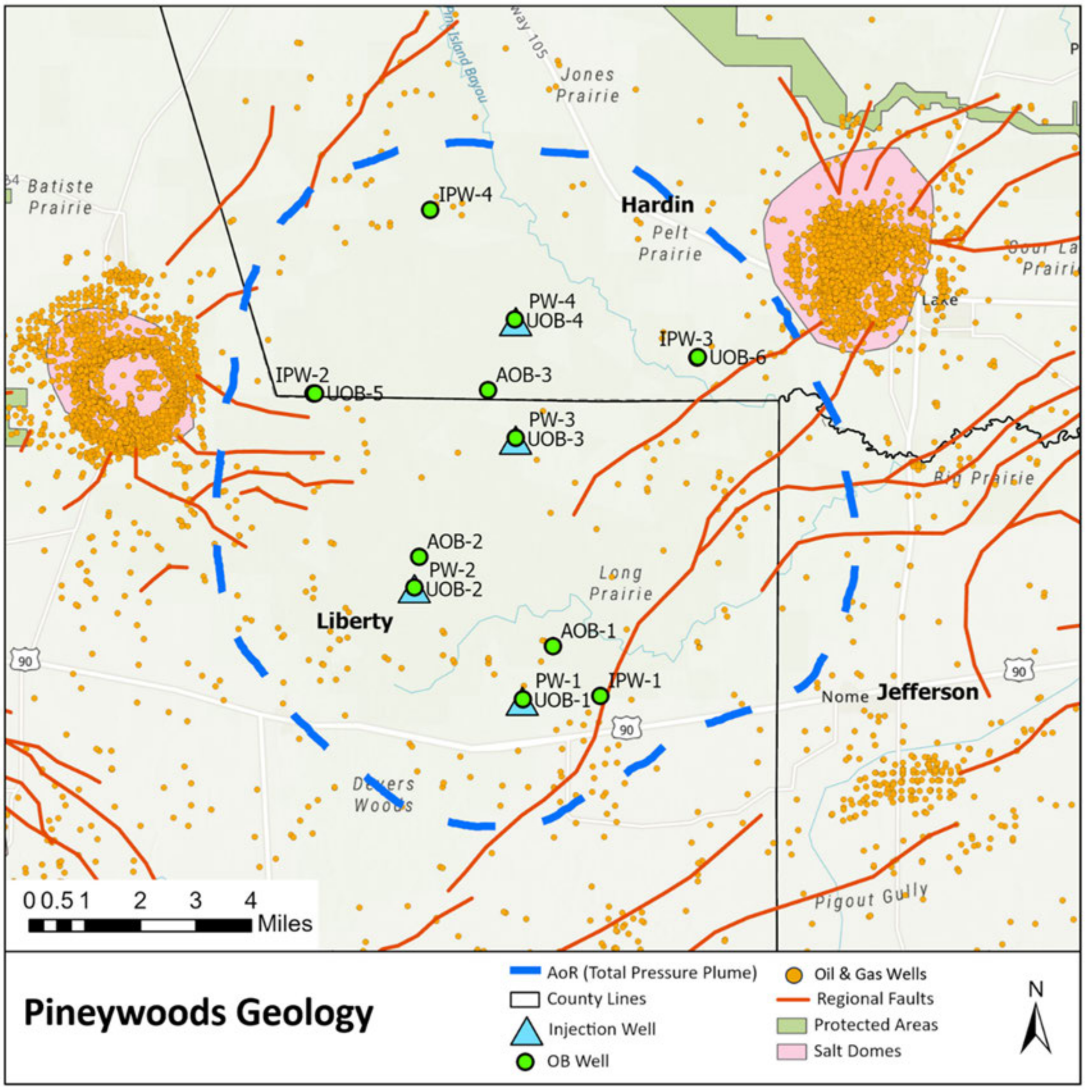

Figure 11: Geologic map of Pineywoods CCS Hub depicting location of the Daisetta and Sour Lake salt domes as well as regionally mapped faults around and near the AOR.

Figure 12 shows a structural cross-section view through the SEM of the Pineywoods CCS Hub. The cross section shows the subsurface structure from the Anahuac Formation (upper confining unit) to the base of the Frio Formation. The Anahuac is shown in blue, and the Frio is shown in green.

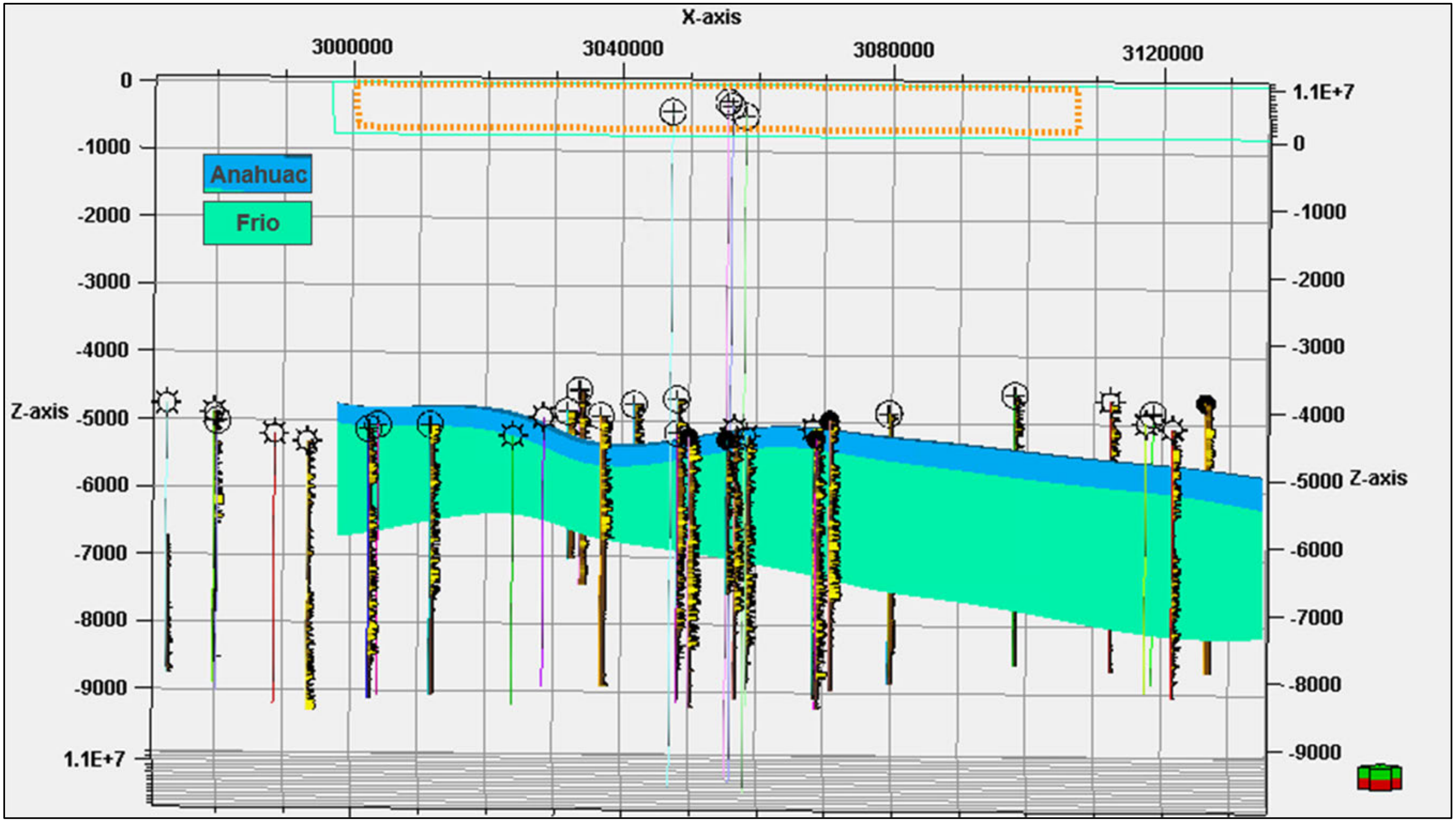

Figure 12: Cross sectional view obliquely from the South of the 3D SEM of Pineywoods CCS Hub. Blue zone is Anahuac, and green zone is Frio Formation.

B.3. Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

The Pineywoods CCS Hub is updip of the major growth faults along the Texas Gulf Coast (**Figure 13**). The Anahuac and Frio Formations have a regional dip to the southeast towards the Gulf of Mexico due to subsidence of the Gulf of Mexico and gravity-driven salt tectonics of the Louann salt movement. The large regional growth faults caused by this subsidence and tectonics are not present within the AOR (USGS, 2013). The Anahuac and Frio Formations pinch out updip (to the northwest) of the Pineywoods CCS Hub.

A generalized schematic diagram (**Figure 14**) shows the relative amount of expansion from growth faulting. The Pineywoods CCS Hub is updip of the maximum expansion zone in the stable shelf. Albeit updip of the major structural deformation along the Gulf Coast, the Pineywoods CCS Hub still sees presence of the Louann salt and associated radial faulting from the salt **(Figure 15).**

Figure 15 shows an uninterpreted and an interpreted 2D seismic line within the AOR. The black lines demark clear offset in seismic reflectivity, indicating the presence of faults, while the white lines indicate seismic discontinuities. Seismic discontinuities can be interpreted as a number of occurrences such as issues with the migration of the data, presence of fluids, changes in localized lithology (channels), or sub-seismic faults.

The base of the proposed injection interval is interpreted by an orange horizon pick on the 2D seismic in Figure 14. The interpretation shows the absence of clear faults within and above the proposed injection interval on this 2D seismic line.

All 2D seismic lines were interpreted, and faults were identified. Faults that reach the surface and faults that intersect the caprock are denoted in **Figure 16**. Two-dimensional seismic data cannot be used to ascertain the orientation and size of faults. To supplement the 2D seismic fault interpretations, other available data sources (GEOMAP, 2022) were also analyzed to identify the location of faults **(Figure 16).** Radial faulting around salt domes intersects the AOR, and only one literature fault is observed to intersect the CO_2 plume at the southernmost end **(Figure 16).**

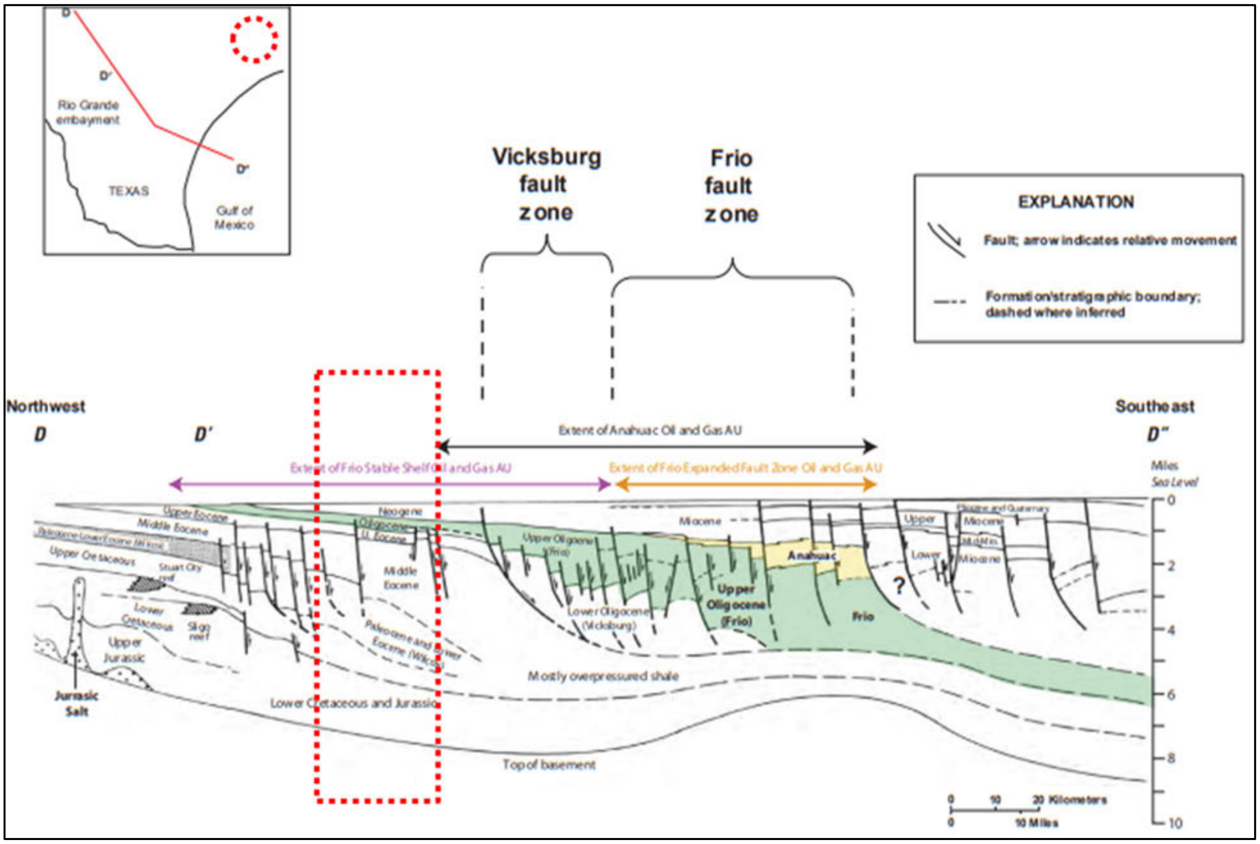

Figure 13: Regional cross section south of the study area depicting the structural setting of the Vicksburg and Frio fault zones. The approximate study area is denoted on the map as a red circle and on the cross section (albeit off strike) as a red box (USGS, 2013

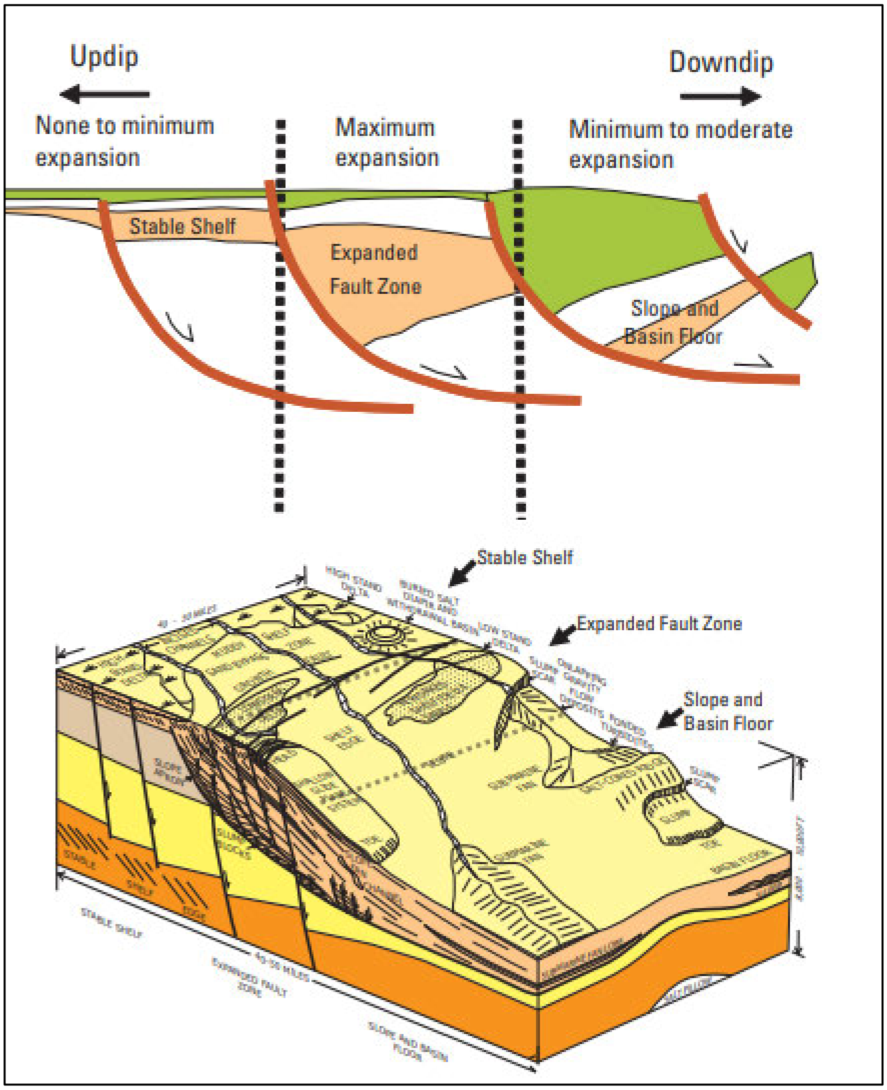

Figure 14: Generalized diagram of structural and depositional systems (USGS, 2013).

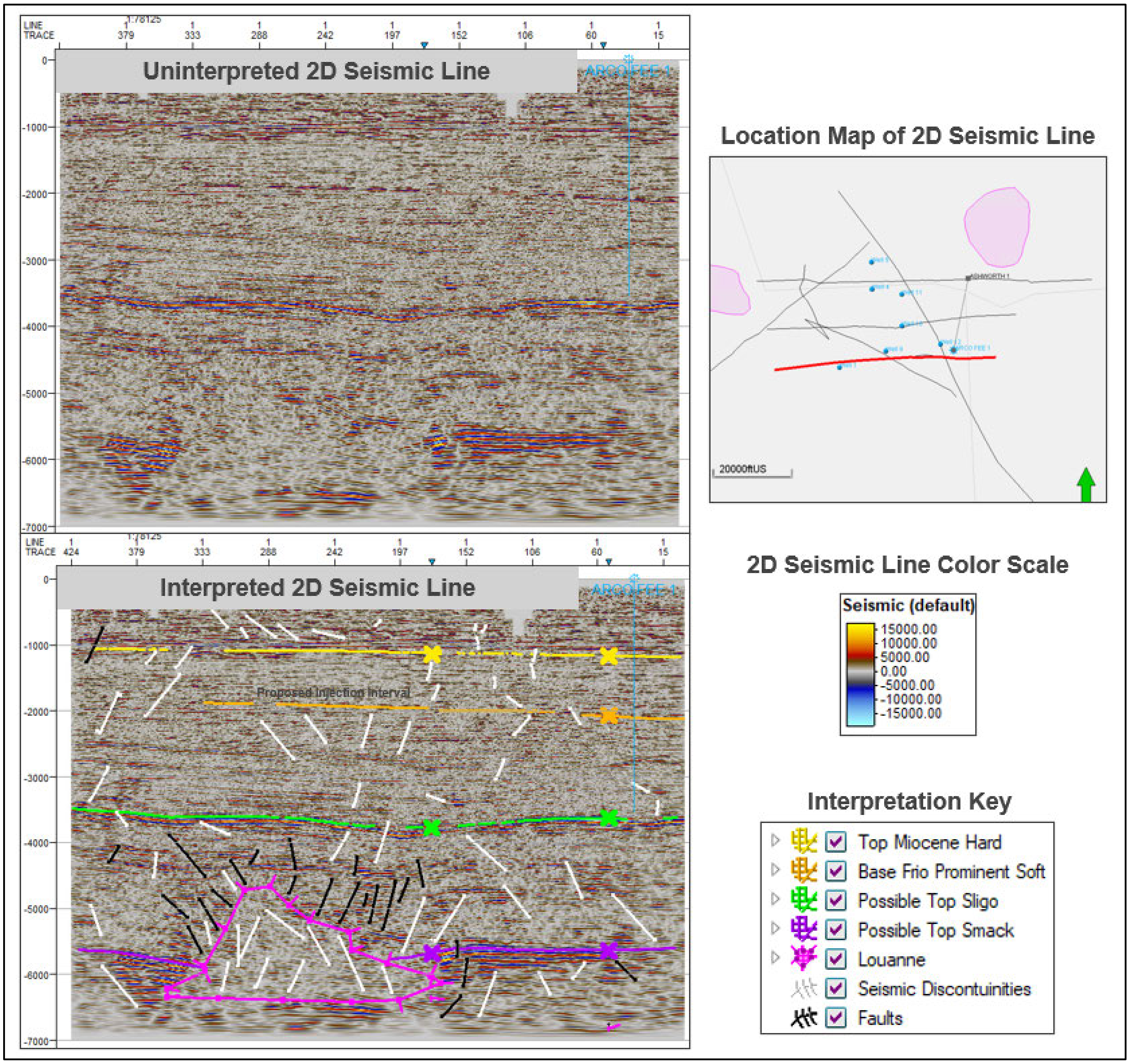

Figure 15: Example of one of the 2D seismic lines used in the assessment. Top uninterpreted, bottom interpreted. The orange pick is the base of the Frio formation which is the proposed injection interval.

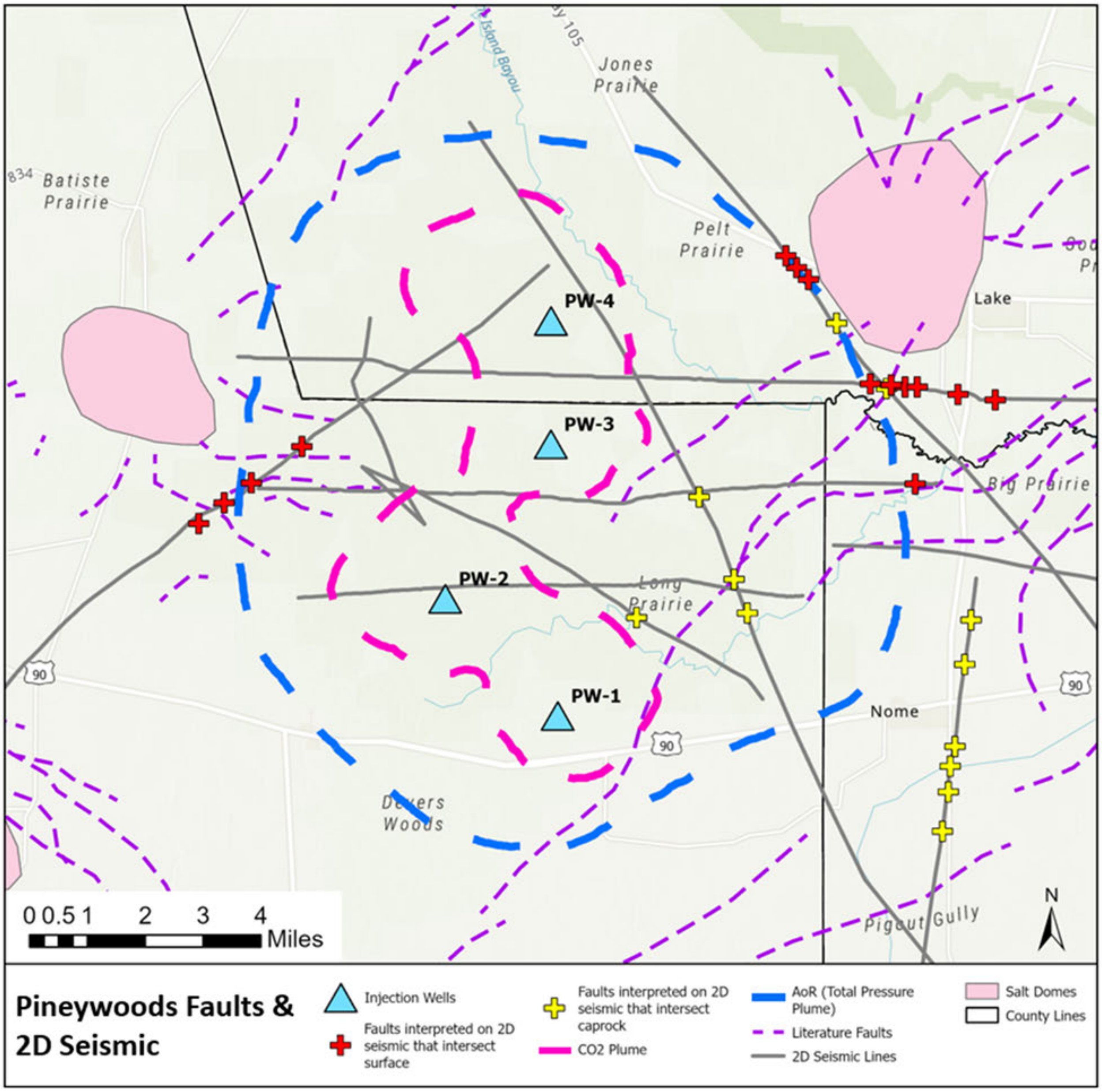

Figure 16: Pineywoods CCS Hub Fault Map depicting literature faults within the AOR and areas where faults were mapped from 2D seismic data.

B.4. Injection Interval — Frio Formation

The Frio Formation consists of interbedded shales and sands and occurs at 5,200 ft SSTVD within the Pineywoods CCS Hub. The vertical thickness of the Frio Formation is 1,900 ft, with 800 ft of interbedded shales in the Upper Frio and 1,100 ft of mostly sands in the Lower Frio, which is the proposed injection zone. The Frio Formation has favorable reservoir properties, including its lateral continuity, porosity of 20 to > 35%, permeability of 100 to > 3,000 mD, and normal hydrostatic pressure and temperature conditions. The Frio also meets EPA's minimum salinity for CO_2 injection and storage (EPA, 2018).

A regional cross section through the study area shows the Frio Formation dipping to the southeast **(Figure 17).** The Pineywoods CCS Hub is denoted by well 27 (Baker, 1995) on the cross section and a red box on the insert map. This regional cross section extends to the Texas Gulf Coast where the maximum expansion zone from growth faulting is present **(Figure 14).** A regional stratigraphic column across the entire Texas coastal plain denotes the lateral continuity of the Anahuac and Frio formations **(Figure 18).**

Using tops picked in well logs on gamma ray (GR) curves as well as 2D seismic reflection data, a structure map of the top of the Frio Formation was created by a convergent interpolation gridding algorithm in Petrel **(Figure 19).** The area of the SEM is denoted with a green square, and the four proposed injection wells are plotted. The top Frio structure map depicts the Frio formation top ranging from around -4,000 to -7,000' SSTVD regionally around the study area and dipping to the southeast as denoted in previous examples of the dip **(Figure 13** and **Figure 17).**

Furthermore, using the available well log data and extrapolating the data across the entire SEM, a facies model was created for the Pineywoods CCS Hub **(Figure 20).** The facies model indicates sands as yellow and shales as brown. Note the graphical presence of the thick Anahuac shale (brown) as the primary upper confining unit and the prominently sandy (yellow) lower Frio Formation (the proposed injection interval). The additional well log, core, and fluid sample data collected during the pre-operational phase will assist in verifying the different characteristics of the injection zone highlighted above and are detailed in the **Pre-Operational Testing Plan**.

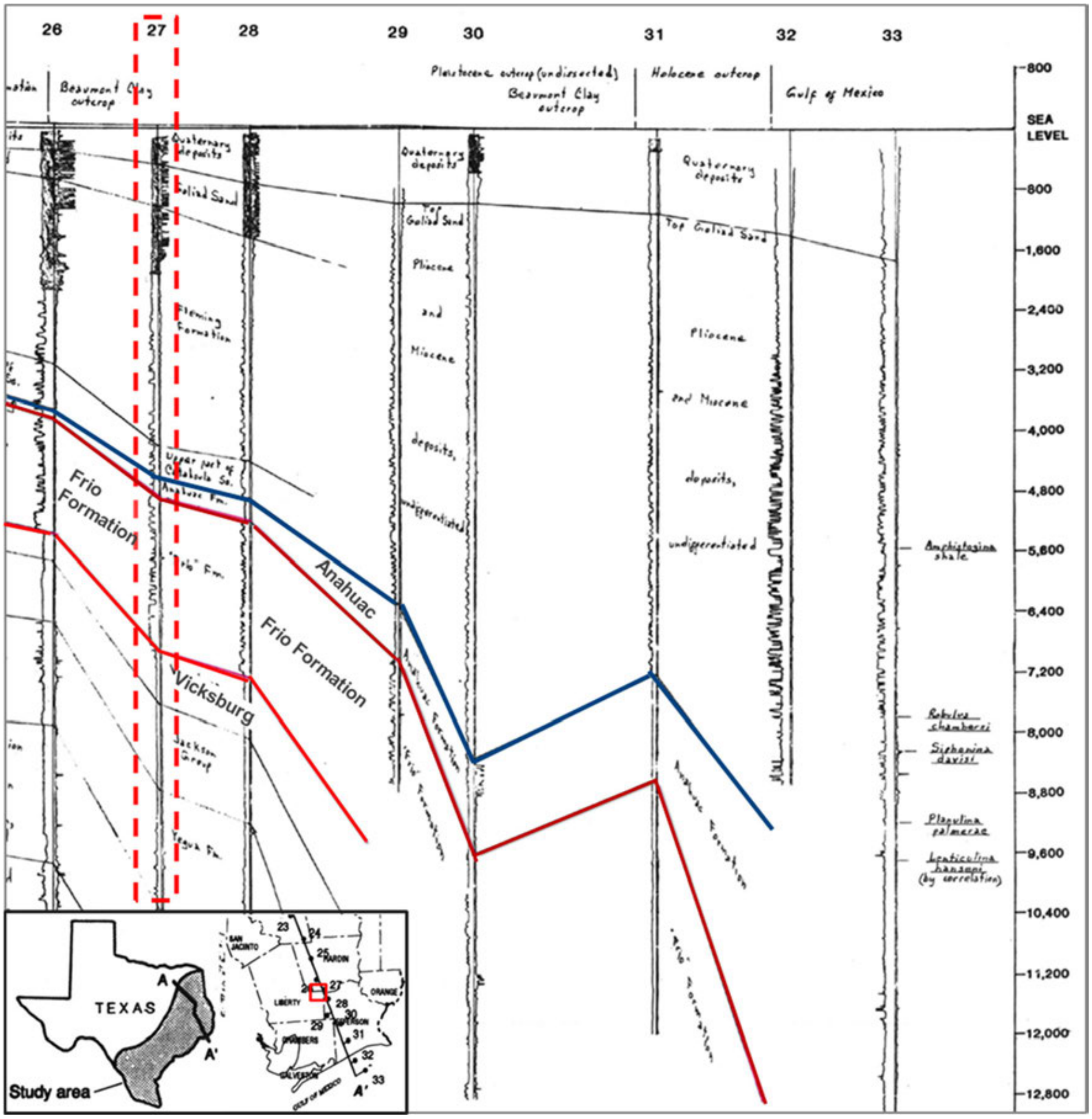

Figure 17: Regional structural cross section through the study area showing the Anahuac and Frio Formation dipping to the southeast. The small red box on the on the inset map shows the approximate project location. The Well-27 in the cross section is inside the Pineywoods CCS Hub and is denoted by the red-dashed line (Baker, 1995).

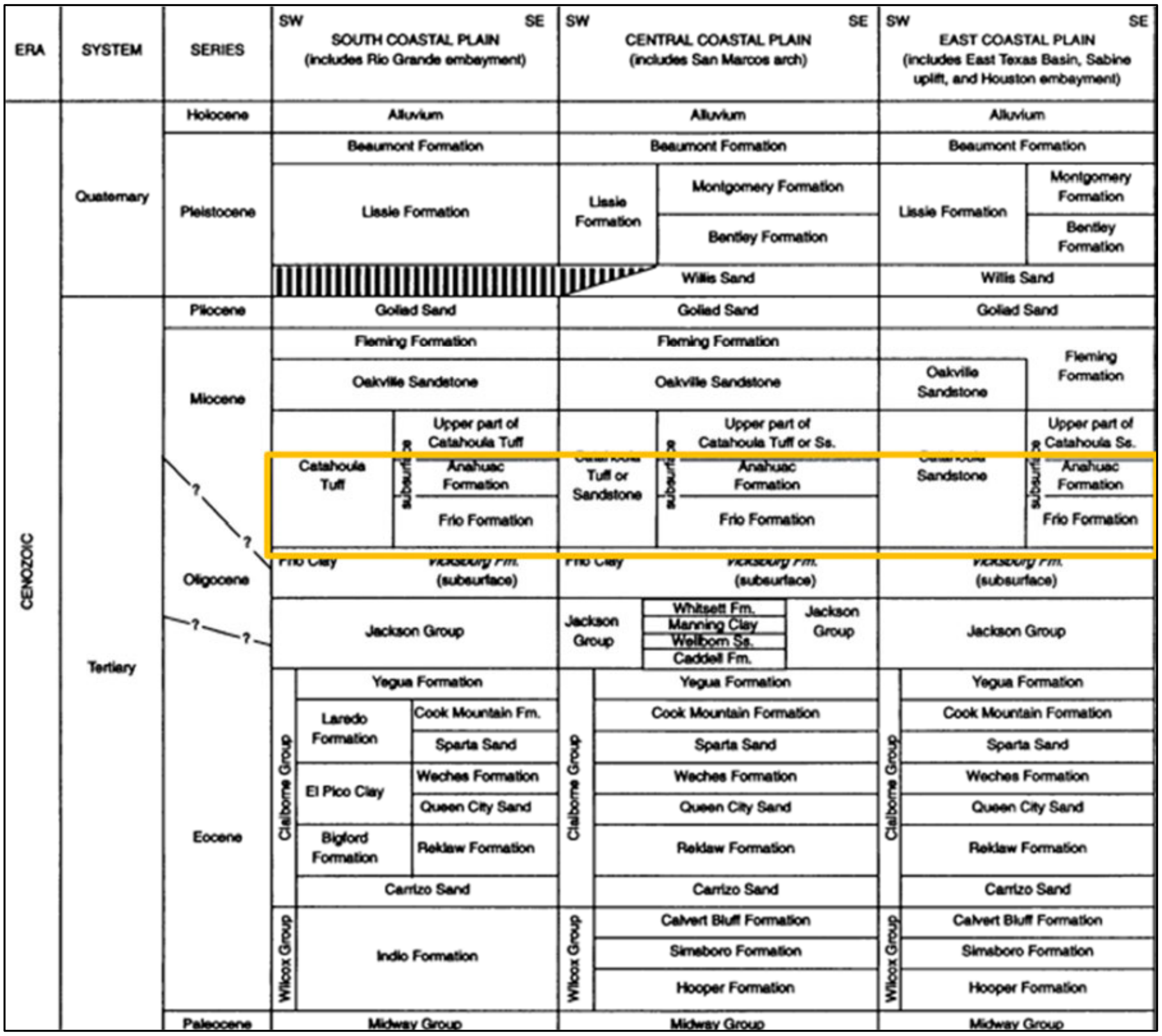

Figure 18: Stratigraphic columns across the continental Texas coastal plain showing lateral continuity of the Frio formation (Baker, 1995).

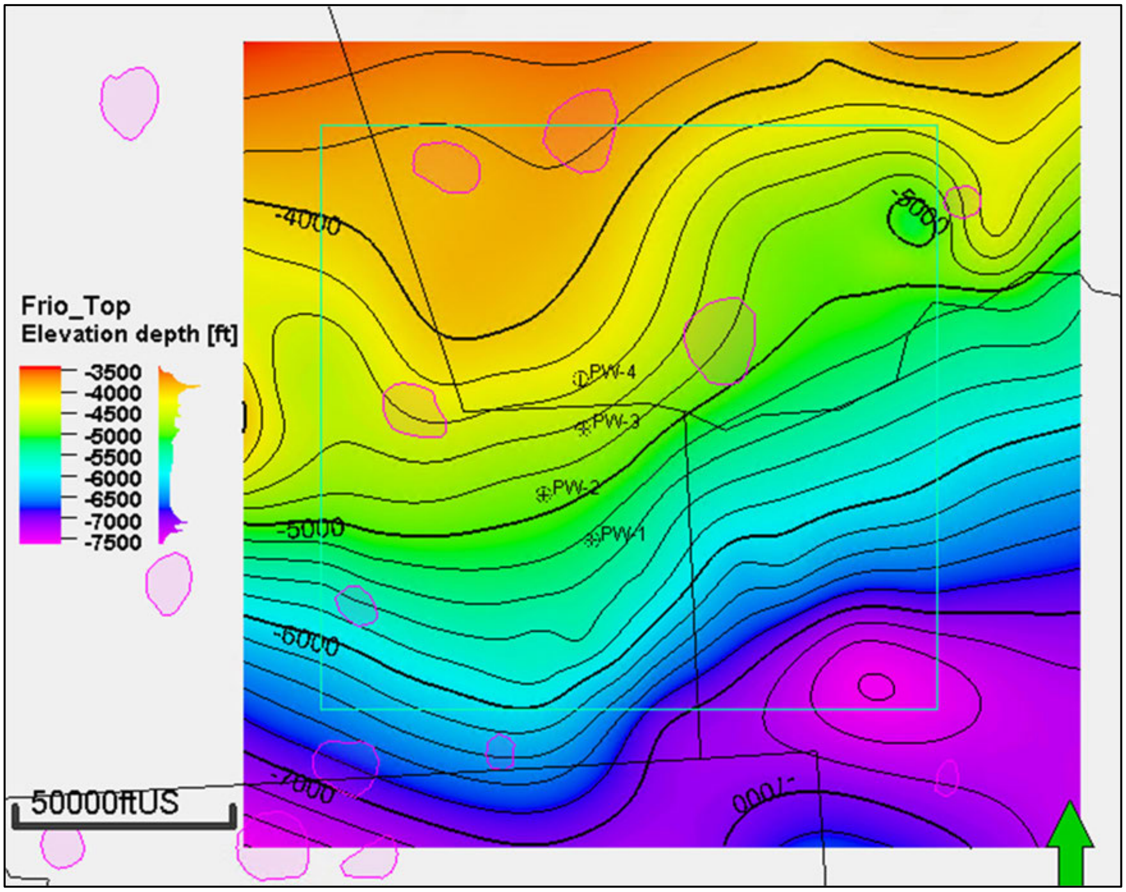

Figure 19: Structure contour map on the top of the Frio Formation as modeled in Petrel.

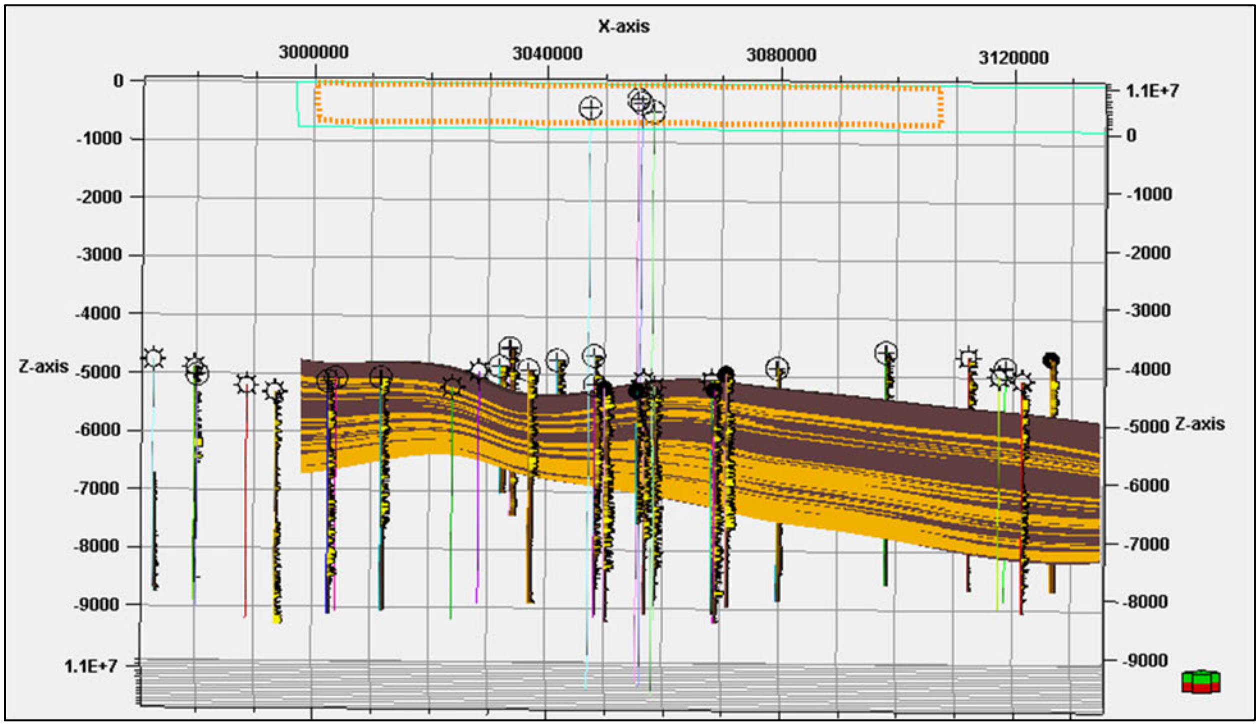

Figure 20: Cross sectional view obliquely from the South of the 3D SEM of the Pineywoods CCS Hub. Brown zones are shale facies, and yellow zones are sand facies. Surface wells are Tenaska proposed well locations.

Mineralogy

The Frio Formation is generally comprised of quartz and feldspar with volcanic and carbonate lithic fragments (Kincade, 2018). The Frio sandstone of the upper Texas Gulf Coast is known to contain a higher percentage of quartz, less feldspar, and fewer volcanic lithic fragments, than the Frio sandstone in the lower Texas Gulf Coast, where it is known to be a feldspathic litharenite (Hovorka, 2003).

Hovorka et al (2005) found the Frio in the South Liberty Oil Field (Liberty County, TX) to be comprised of quartz, labradorite, and potassium feldspar, with minor amounts of illite/muscovite, calcite, kaolinite, dolomite, and pyrite as shown in **Table 3**. Other secondary minerals found to be present in the Frio formation include.

Havorka (2009) observed that after pilot-scale injection operations, fluid samples obtained from the Frio injection and observation wells showed an unexpected rapid increase in concentrations in Fe (from 30 to 1,100 mg/L), manganese, and other metals after CO_2 breakthrough. The investigators used geochemical data, laboratory studies, and modeling to determine that increased metal concentrations likely were sourced from either: 1) dissolution of Fe-oxyhydroxides; 2) corrosion of tubing; or 3) a combination of reactions. Havorka et al (2009), interpreted that high-surface area clays coating Frio sand grains (**Figure 21**) may be a source for metal mobilization within the subsurface.

Table 3: Mineralogy Percentages (from Hovorka, 2005).

Mineral	Volume (%)
Quartz	71.0
K-feldspar	9.0
Labradorite	13.0
Illite/muscovite	4.9
Calcite	0.4
Kaolinite	0.3
Dolomite	1.0
Pyrite	0.4

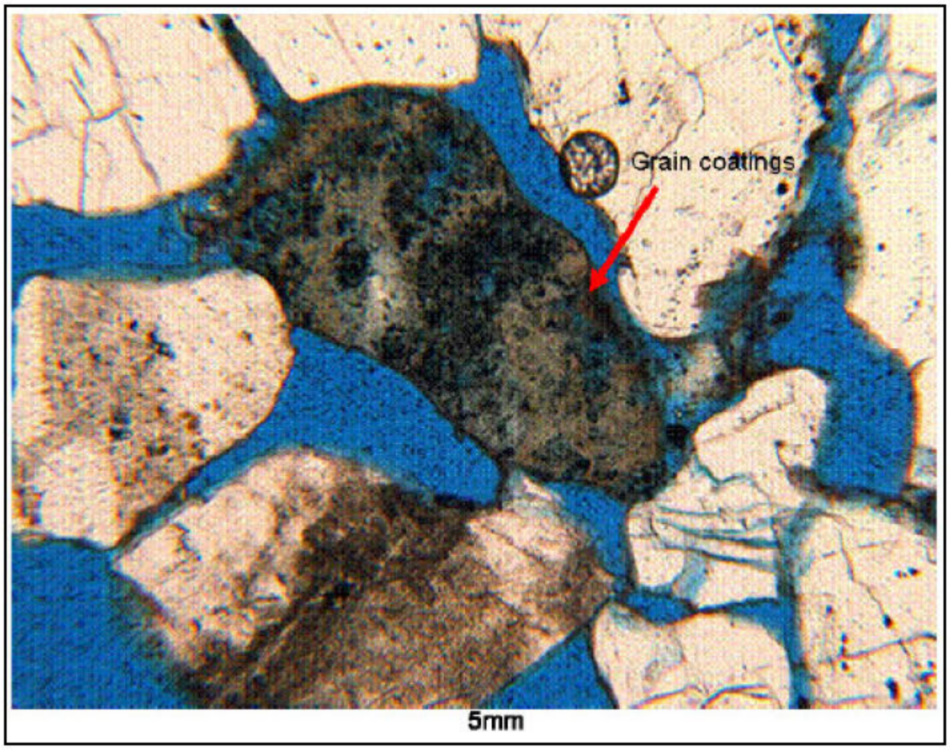

Figure 21: Thin Section of Frio "C" sandstone displaying clay coated sand grains, a possible source of Fe and Mn which may be mobilized as a result of CO2 injection (from Havorka, 2009).

Porosity and Permeability

Effective porosity values for the Frio Formation were derived from the neutron and density porosity logs from multiple wells within the SEM for clean sand and pure shale interval. Overlap of the density and neutron porosity logs indicate a clean sand, and it was set as a reference for clean sand identification (Bassiouni, 1994). Then effective porosity for intermediate facies were determined using the V_{shale} formulation that accounts for the shale content in the strata from multiple well logs, where porosity information for the storage interval was available. The average effective porosity values and range of porosity values are summarized in **Table 4** for the Frio.

Table 4: Average Porosity and Estimates for Perforated Frio Interval.

Injection Interval	Average Effective Porosity (%)	Effective Porosity Range (%)
Lower Frio	0.202	0.005 - 0.355

For the Frio Formation, a permeability-porosity correlation based on Frio Pilot Test core data was used (Hovorka, 2006). The porosity-permeability relationship is shown in **Figure 22**. These transform functions are used to calculate the average horizontal permeability within the reservoir. A vertical to horizontal permeability ratio of 0.2 was then used to calculate the vertical permeability from the horizontal permeability.

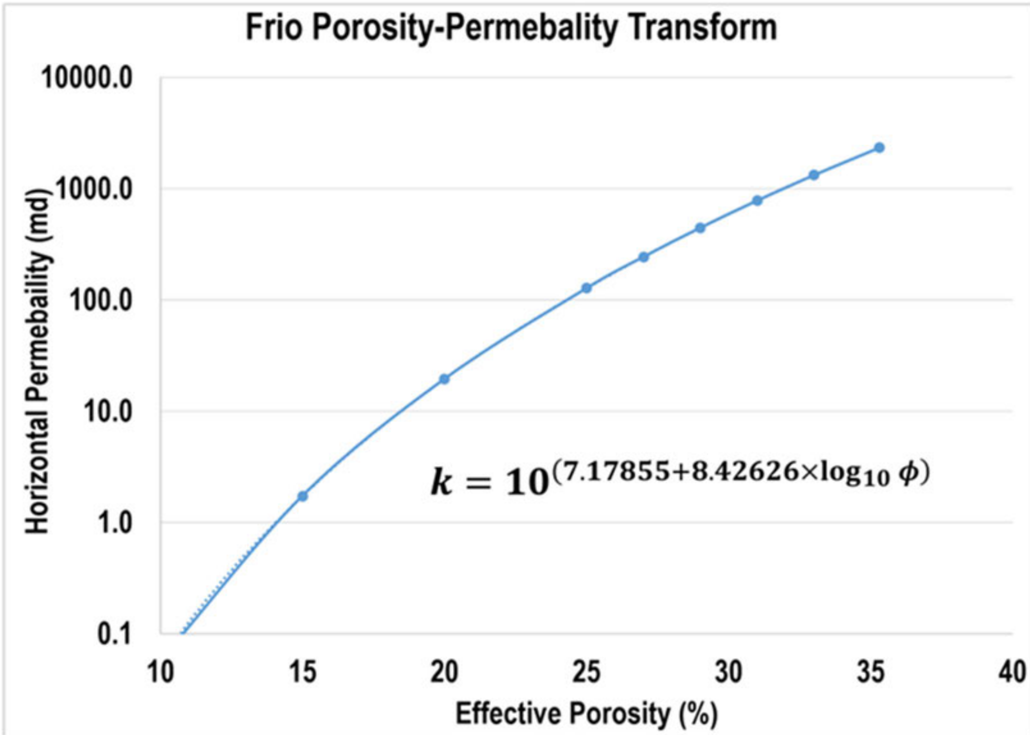

Figure 22: Frio porosity-permeability cross plot based on modeled porosity and permeability values from the geologic model.

Reservoir Pressure

The pressure gradient of the Frio Formation at the Pineywoods CCS Hub is 0.465 psi/ft based on regional trends data for the normally pressured formation in the Gulf of Mexico (Burke et al., 2012). A similar trend is observed in a nearby well (API-4219932965) from a very thin gas reservoir in the top of the Frio formation (TRC, 2023). This pressure gradient, alongside the formation pressure used for initial pressure conditions in the reservoir model are shown in **Table 5.**

Table 5: Pineywoods CCS Hub Initial Reservoir Pressure.

Hydrogeologic Unit	Reference Depth (ft)	Pressure Gradient (psia/ft)	Formation Pressure (psia)	Source
Frio (Upper +Lower)	6,186	0.467	2,892	Burke et al., 2012
Frio (Upper)	4,764	0.467	2,226	Initial production potential test of well API # 4219932965

Reservoir Temperature

The Frio Formation initial temperature is estimated from the well log header data of several legacy oil and gas wells in the area (API #: 4219932031, 4219932859, 4219992859, 4219932508, 4219932965, 4219925422) for normally pressured formations. This data is summarized in **Table 6**. Reservoir reference depths and temperature values based on the 1.3275 °F / 100 ft temperature gradient was used as inputs in the reservoir model. Reservoir temperature values were then automatically calculated for the reservoir layers in the model by depth.

Table 6: Pineywoods CCS Hub Reservoir Temperatures.

Hydrogeologic Unit	Reference Depth (ft)	Temperature (°F)	Temperature Gradient (°F/100ft)
Frio	6,186	152.12	1.3275

Capillary Pressure

The capillary pressure data for the Frio Sand Formation was adopted from the Frio Pilot Test data (Jung, 2017) and is shown in **Figure 23**. It is reported in literature that the Anahuac Formation has a very high capillary entry pressure of 3,500 psi (Hovorka, 2009). These high entry capillary pressures mean that the CO_2 pressure in the injection zone needs to exceed these values to enter the 100% brine saturated caprock pores. As a conservative approach, capillary pressures are excluded for the shale layers to allow CO_2 migration into the caprock with small pressure increases. However, because of the very low permeability of the shale layers, CO_2 stays within the Frio Formation and does not leak.

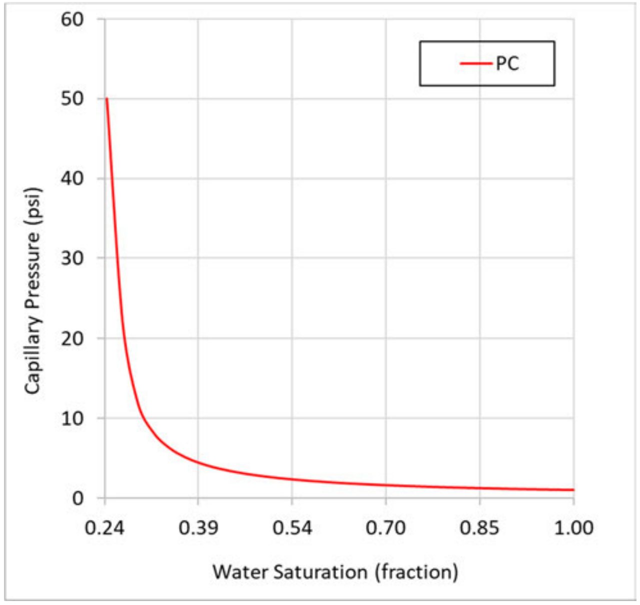

Figure 23: Pineywoods CCS Hub Computational Model Frio Capillary Pressure Curve.

Static Storage Resource Potential

Based on these petrophysical and reservoir characteristics, the P10, P50, and P90 Static Storage Potential for the Lower Frio Formation was calculated to be 13.09, 24.76, and 42.45 MMt per square mile, respectively using the NETL methodology (Goodman et al. 2011). A summary of the parameters and calculations estimating static CO_2 storage resource potential for the Lower Frio Formation is provided in **Table 7.**

Table 7: Estimate of Static CO_2 Storage Resource Potential for the Lower Frio Formation.

Estimate of Static CO_2 Storage Resource Potential		
Producing Interval		Lower Frio
Gross Thickness (ft)		1,100
Avg Total Porosity (%)		30
Average Depth (ft)		6,550
Avg Pressure (psi)		3,046
Reservoir Temperature (°F)		157
CO_2 Density (lb/ft^3)		42.38
Storage Potential ($MMt/mi.^2$)	P10 (7.4% Efficiency)	13.09
	P50 (14% Efficiency)	24.76
	P90 (24% Efficiency)	42.45

B.5. Confining Zones

B.5.1. Primary Confining Zone – Anahuac Formation

The Frio Formation lies below the Anahuac Formation, a well-known regional marine shale confining zone. It represents a complete transgressive and regressive cycle (Holcomb, 1964). It is regulatorily defined as confining for many Class I UIC wells and serves as seal for many oil and gas reservoirs (Hovorka, 2009). There are several other overlying sandstone-shale pairs above Anahuac which provide redundancy in confining zones (see **Figure 24** and **Section B.5.2** below). **Table 8** summarizes the attributes of the primary, secondary, and tertiary confining zones.

Table 8: Summary of primary and secondary confining zones.

Formation Name	Lithology	Formation Top Depth (ft. subsea)	Thickness (ft.)	Depth Below Base of USDW (ft.)
Anahuac	Marine Shale	5,000	370	4,763
Marginulina A.(Marg. A)	Marine Shale	4,100	300	3,863
Amphistegina chipolensis	Marine Shale	3,700	200	1,330

A high capillary entry pressure of 3,500 psi was noted for the Anahuac Formation in the nearby Frio-Pilot Test project (**Figure 8**), confirming it to be a good top seal for CO_2 (Hovorka, 2009). These high entry capillary pressures mean that the CO_2 pressure in the injection zone needs to exceed these values to enter the 100% brine saturated caprock pores.

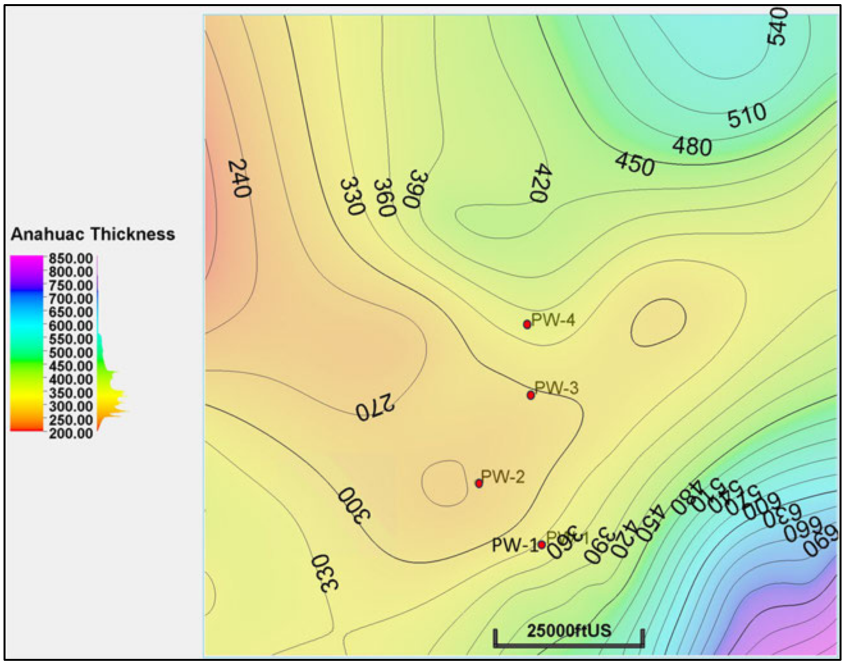

Figure 24: Vertical thickness map of the primary seal Anahuac Formation. Contour interval: 30 ft.

The operational conditions are not expected to create these high pressures. The subsea elevation of the top of Anahuac formation is shown in **Figure 24**. Conventional core data for the primary confining Anahuac shale in some of the waste disposal wells (WDW) show a permeability distribution in the range of 0.001 mD to 0.001 nD and total porosity between 5 to 21% (WDW397, WDW188, WDW230 (TCEQ, 2023)). On average, the caprock has 0.001 md permeability.

The Vicksburg formation forms the base of the Frio Formation. In the Pineywoods CCS Hub, Vicksburg is a several hundred feet thick shale unit, as shown for Well 27 in Figure 17 (Baker, 1995). Therefore, CO_2 is not expected to migrate to this zone.

<u>Mineralogy</u>

The Anahuac shale is comprised of 41% Clay, 28% quartz, 20% calcite, and 12% other minerals. The Anahuac clay mineralogy is a mixed layer clay system comprised of 75% illite/smectite, 11%, illite/ mica, 11% Kaolinite and 3% chlorite (Hovorka at al, 2005).

B.5.2. Secondary Confining Intervals

The Anahuac Formation is overlain by Miocene interbedded shale/sandstones interval. It is usually divided into four distinct sub-intervals of Upper, Middle, and Lower Miocene-1 (LM1), and Lower Miocene-2 (LM2) (see **Figure 8**). Regional transgressive shale forms the boundary of these units (USGS, 2004; Meckel et al., 2017). Marginulina Ascensionensis (Marg. A) is the shale package that overlies the LM1 (**Figure 25**). It is approximately 250 ft thick in the reference well shown in **Figure 26**. The relative location of this reference well is denoted by a red circle in **Figure 25**. The formations in the area dip mostly in the northwest direction and usually thin out in the northernwestern direction. Therefore, it is expected that the thickness of the secondary confining interval may decrease in the northern direction from the refence well.

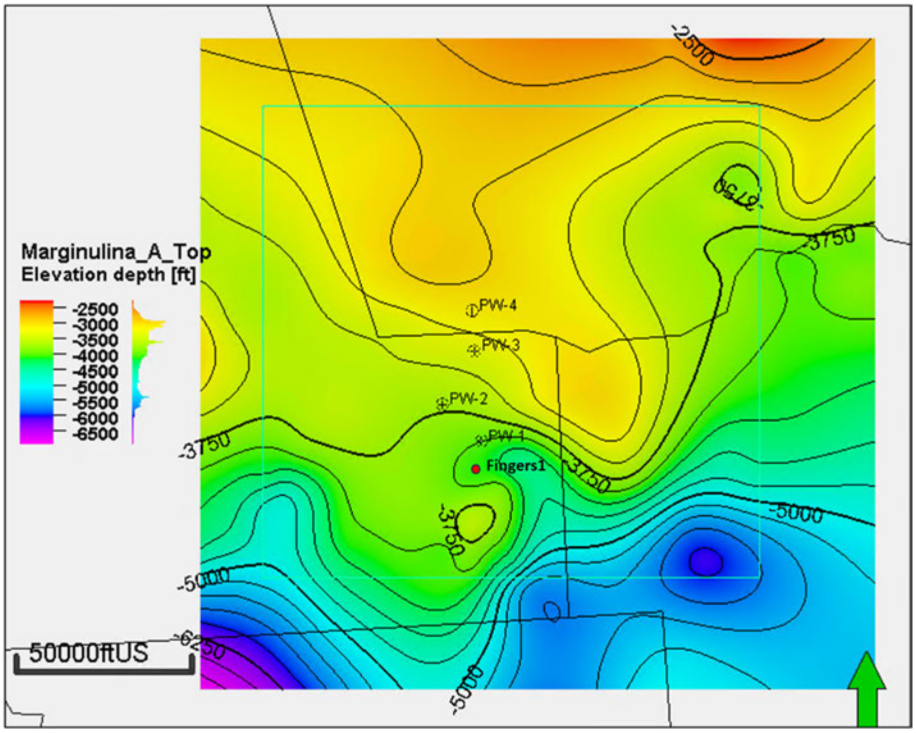

Figure 25: Structure contour map of the top of Marg. A shale, a secondary confining unit, as modeled in Petrel. Location of the reference well used in Figure 25 is shown as red dot.

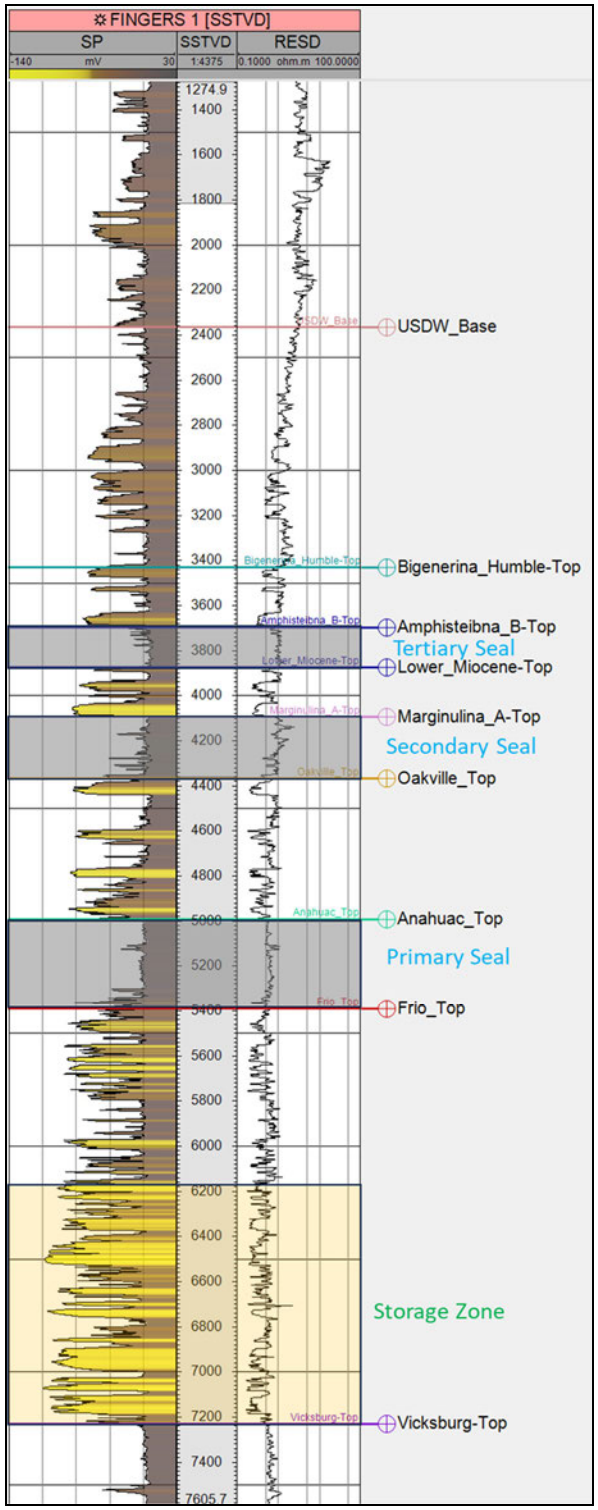

Figure 26: A sample SP log for a well approximately 1.8 mile south of PW-1, showing primary, secondary and tertiary confining units between the storage zone and the lowermost USDW depth.

B.5.3. Tertiary Overlying Confining Interval

The Amphistegina chipolensis (Amph. B) is another distinct regional well-known marine shale overlying the LM2 interval and dividing the lower Miocene interval from the middle Miocene interval (Galloway, 2008). **Table 8** provides additional information about the Amph. B shale. Additional shale layers can be spotted in the sample well log in **Figure 26**. The secondary and tertiary seal alongside additional shale layer pairs can provide additional redundancy in the confining zones.

B.6. Geomechanical and Petrophysical Information of the Confining Zones [40 CFR 146.82(a)(3)(iv)]

The **Area of Review and Corrective Action Plan** details current assumptions regarding formation temperature, pressure, and pore pressure gradient. The resulting computational modeling used 0.63 psi/ft as the maximum allowable downhole pressure gradient to determine the CO_2 injection rate, the surface CO_2 injection pressure, and the CO_2 mass that can be injected at the Pineywoods CCS Hub.

A site-specific geomechanical characterization effort is planned with the use of micro-image logs, wireline well tests, and laboratory core tests as detailed in the **Pre-Operational Testing Plan**. Acquisition of this data will be undertaken during the construction of new observation and injection wells in the storage area. Physical properties that will be determined from samples collected from these wells include bulk density, porosity, permeability, Young's modulus, Poisson's ratio, and failure strength, to determine:

- Fracture/parting pressure of the sequestration zone and primary confining layer, and the corresponding fracture gradients are determined via step rate or leak-off tests;
- Rock compressibility, or measure of rock strength, for the confining layer(s) and sequestration zone;
- Rock strength and the ductility of the confining layer(s); and
- Unconfined compressive strength (UNC) of the confining layer as measured from intact samples.

B.7. Seismic History [40 CFR 146.82(a)(3)(v)]

The Pineywoods CCS Hub is located within a relatively aseismic area, with no known source of natural seismicity in the AOR or region that would compromise the containment of CO_2. The USGS-published National Seismic Hazard Map shows the frequency of damaging earthquake shaking expected in a 10,000-year period (**Figure 27**). The Pineywoods CCS Hub is at low risk of damaging earthquakes, with less than 2 expected within a 10,000-year period.

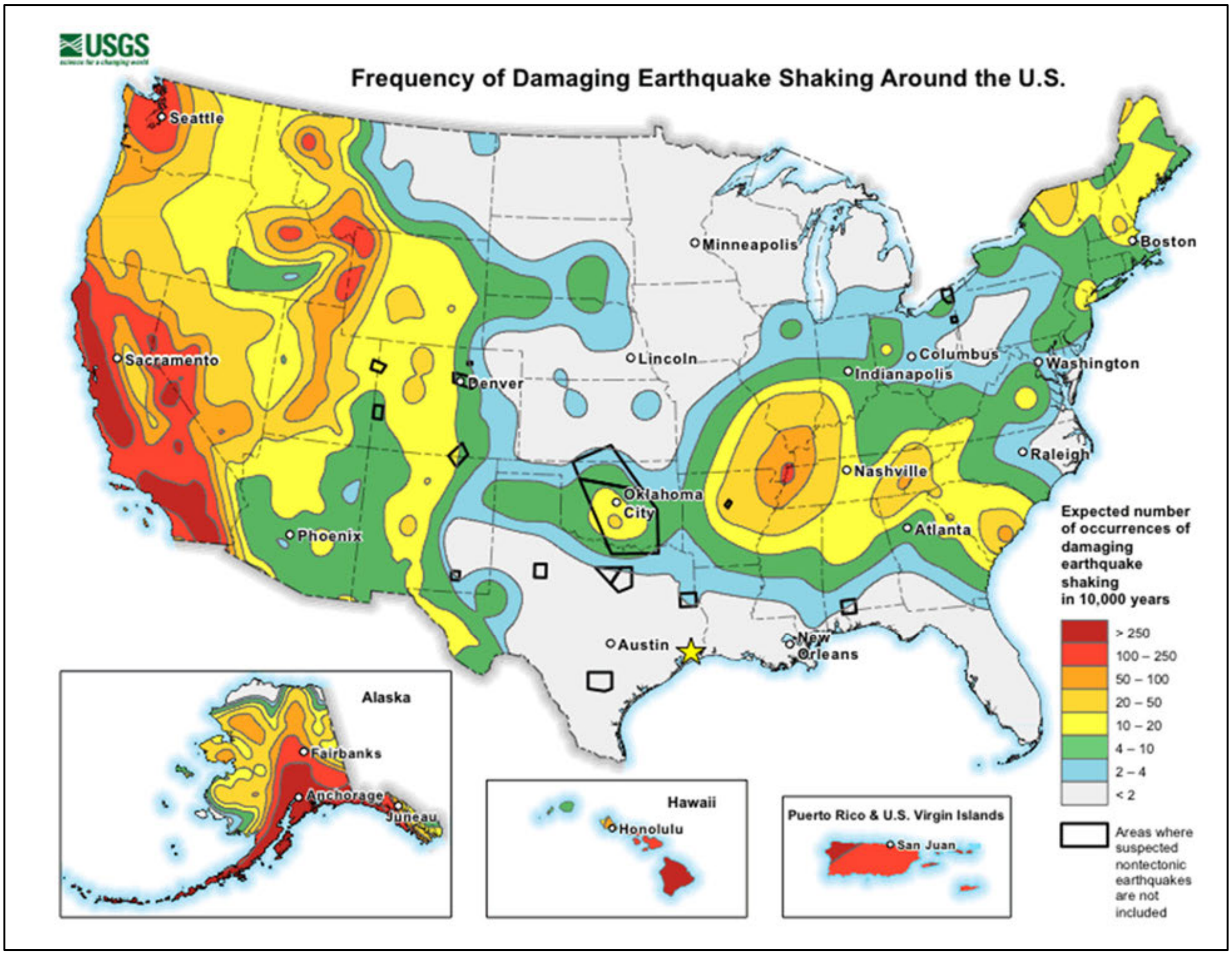

Figure 27: USGS Seismic Hazard Map, showing the frequency of damaging earthquake shaking within a 10,000-year period (Petersen et al., 2008). The Pineywoods CCS Hub is indicated by the star on the map in eastern Texas.

The Gulf Coastal Plain of Texas, where the Pineywoods CCS Hub is located, is a region of low natural seismicity, with any earthquakes that do occur being of low magnitude. The TexNet Earthquake Catalog does not show any recorded earthquakes within 50 miles of the Pineywoods CCS Hub region since at least 2016. In fact, the only recorded earthquake within 100 miles of the project area took place approximately 60 miles away near Lake Charles, Louisiana, in 1983, and according to Stevenson and Agnew (1988) had a maximum Modified Mercalli intensity of V (moderate; felt by nearly everyone, with some dishes or windows broken and unstable objects overturned). Peak ground acceleration (as a percentage of the gravity constant 9.8 m/s^2) with a 2% likelihood of being exceeded within a 50-year period is illustrated for Texas in **Figure 28**. The peak ground acceleration for the project area is estimated to be 2 to 4 percent of gravity, which would correlate to a Modified Mercalli Intensity of IV-V (light to moderate shaking with limited damage to unstable or delicate objects).

Section D of the **Emergency and Remedial Response Plan** includes information on conducting a formal risk assessment of potential risk scenarios, including induced seismicity.

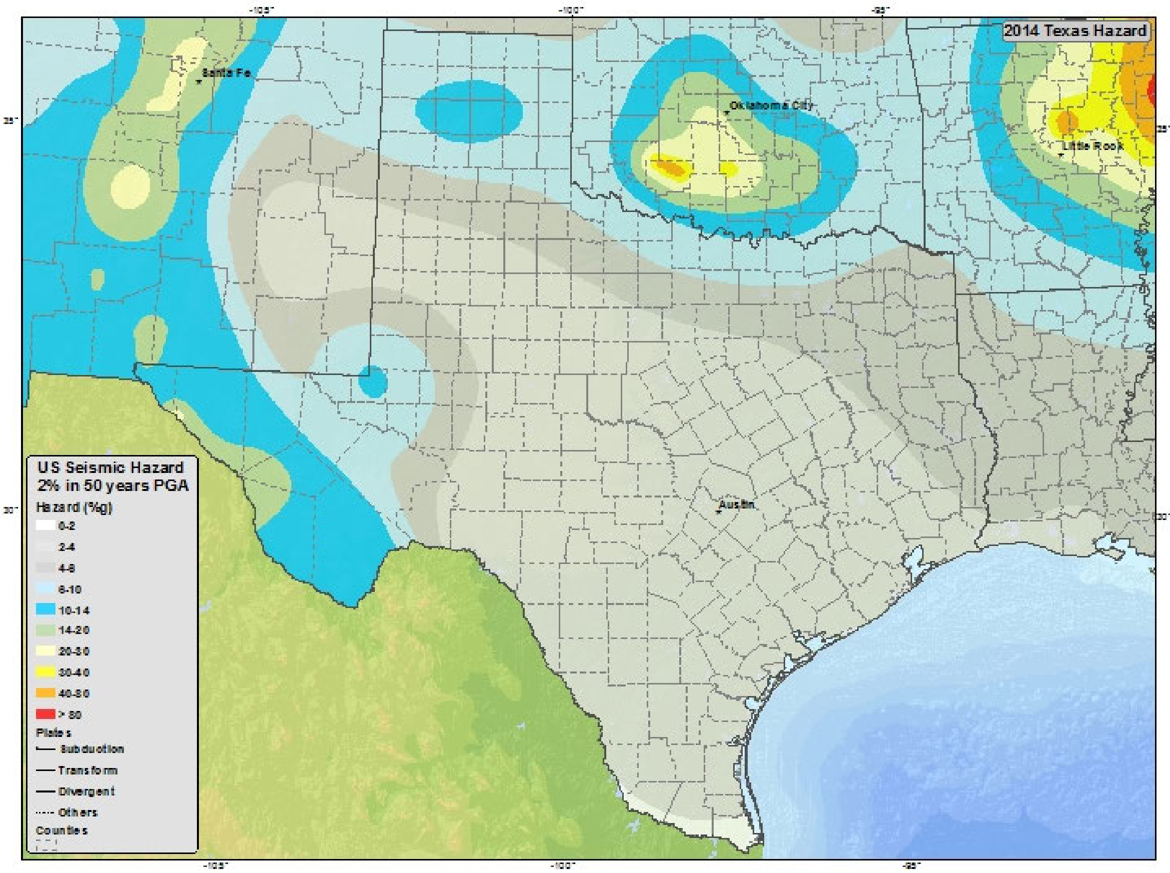

Figure 28: 2014 Seismic Hazard Map of Texas from the USGS National Seismic Hazard Maps illustrating the peak ground acceleration with a 2% likelihood of being exceeded within a 50-year period (US Geological Survey, 2014).

Since at least 1925, earthquakes associated with oil and gas production have occurred in Texas. Frohlich et al. (2016) reviewed Texas earthquakes associated with petroleum production to categorize their likelihood of having been induced. In this study, Goose Creek Field, located south of Houston approximately 50 miles from the Pineywoods CCS Hub, was the only nearby area that had indication of probable induced seismicity. Seismicity near the Goose Creek Field occurred in 1925 and was accompanied by ground subsidence of up to about 3 feet; induced seismicity was associated with the withdrawal of oil and water during production. More recent production in the region has shown no evidence of induced seismicity. Seismic stations within 50 miles of the Pineywoods CCS Hub are listed in **Table 9**.

Table 9: Seismic stations listed in TexNet within 50 miles of the Pineywoods CCS Hub.

Network Code	Station Code	Latitude (DMS)	Longitude (DMS)	Affiliation/ Place	Start Date	End Date
4T	EL01	29° 36' 47.17N	95° 8' 12.86W	Ellington AFB	11/5/21	NA
4T	EL02	29° 35' 26.07N	95° 9' 59.05W	Ellington AFB	11/5/21	NA
4T	EL03	29° 37' 21.51N	95° 10' 28.31W	Ellington AFB	11/5/21	NA
4T	EL04	29° 33' 49.35N	95° 18' 33.59W	University of Texas	3/10/22	NA
4T	EL05	29° 38' 49.86N	95° 17' 12.35W	University of Texas	4/26/22	NA
4T	EL06	29° 39' 36.31N	95° 10' 25.11W	University of Texas	3/29/22	NA
4T	EL07	29° 39' 12.51N	95° 4' 57.45W	University of Texas	12/1/21	NA
4T	EL08	29° 34' 2.35N	95° 7' 28.86W	University of Texas	11/18/21	NA
N4	441B	30° 44' 59.28N	93° 11' 23.27W		1/14/14	NA
TX	HNVL	30° 45' 23.15N	95° 27' 59.99W	Huntsville TX	4/6/17	12/9/21

B.8. Hydrogeologic Information/Maps and Cross Sections of USDWs [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

B.8.1. Regional Hydrogeologic Information

The Gulf coast aquifer is the major aquifer in the project area. It extends over 430 miles along the Texas-Louisiana border to the Texas-Mexico border. The aquifer has been divided into five units, each of which can be generally correlated to different sedimentary formations (Baker, 1979) with different hydraulic properties (Chowdhury and Mace, 2003; Chowdhury and others, 2004; Kasmarek and Robinson, 2004). The units are listed here from oldest (deepest) to youngest (shallowest):

1- **Catahoula**: The Catahoula is the lowermost stratigraphic unit of the Gulf Coast Aquifer, including the Frio Formation, the Anahuac Formation, and the Catahoula Tuff or Sandstone. It is aquitard everywhere except near the outcrop (Wood at al., 1963).
2- **Jasper**: The Catahoula is overlain by the Jasper aquifer, which consists of the Oakville Sandstone and Fleming Formation.
3- **Burkeville**: The Burkeville confining system consists mainly of silt and clay and corresponds to the Lagarto clay formation.
4- **Evangeline**: The Evangeline aquifer has a high sand-clay ratio and contains sand beds tens of feet thick. The Goliad formation is approximately equivalent to the Evangeline Aquifer,

although it also includes underlying Fleming sand locally (Baker, 1979).

5- **Chicot**: The shallowest unit, the Chicot aquifer, is made up of the Willis Sand, the Bentley and Montgomery formations, the Beaumont Clay, and alluvial deposits at the surface (Baker, 1979). Therefore, it comprises all sands between the top of the Evangeline and the land surface.

The main attributes of all subunits of the Gulf Coast aquifer are shown in **Figure 29.** Fluvial-deltaic or shallow marine depositional environment were the most prevalent sediment depositional environment. Repeated sea-level transgression and regression and basin subsidence caused development of cyclic sedimentary deposits composed of discontinuous sand, silt, clay, and gravel (Young et al., 2012). The location of the project area relative to the regional cross section and the approximate depths of different aquifers are shown in **Figure 30.**

ERA	Period		Epoch	Age (M.Y.)	Stratigraphic Unit	Dominant Lithology	Hydrogeologic Unit	
Cenozoic	Quaternary		Holocene	0.02	Alluvium	sand	Alluvium/Beaumont Aquifer	Gulf Coast Aquifer
			Pleistocene		Beaumont	sand		
				1.8	Lissie/Alta Loma	sand	Chicot Aquifer	
	Tertiary	Neogene	Pliocene	5.3	Willis	sand		
			Miocene		Goliad	sand	Evangeline Aquifer	
					Fleming/Lagarto	mud	Burkeville Aquitard	
				23.9	Fleming/Oakville	sand	Jasper Aquifer	
		Paleogene	Oligocene		Catahoula/Frio/Anahuac	sand and mud	Catahoula	
				33.9	Vicksburg	mud	aquitard	
			Eocene		Jackson	sand and mud	Yegua-Jackson Aquifer	
					Yegua	sand and mud		
					Sparta	sand	Queen City-Sparta Aquifer	
					Queen City	sand and mud		
					Reklaw	mud	aquitard	
				55.8	Upper Wilcox/Carrizo	sand	Carrizo-Wilcox Aquifer	
			Paleocene		Middle Wilcox	mud		
					Lower Wilcox/Simsboro	sand and mud		
				65.5	Midway	mud	aquitard	
Mesozoic	Cretaceous	Upper				carbonate		
		Lower		145.5	Edwards	carbonate	Edwards (BFZ) Aquifer	
	Jurassic	Upper				carbonate		
		Middle		201.6	Louann salt	evaporite	salt domes	
	Triassic							

Figure 29: Regional hydrological units and dominant lithological units (Young et al., 2012).

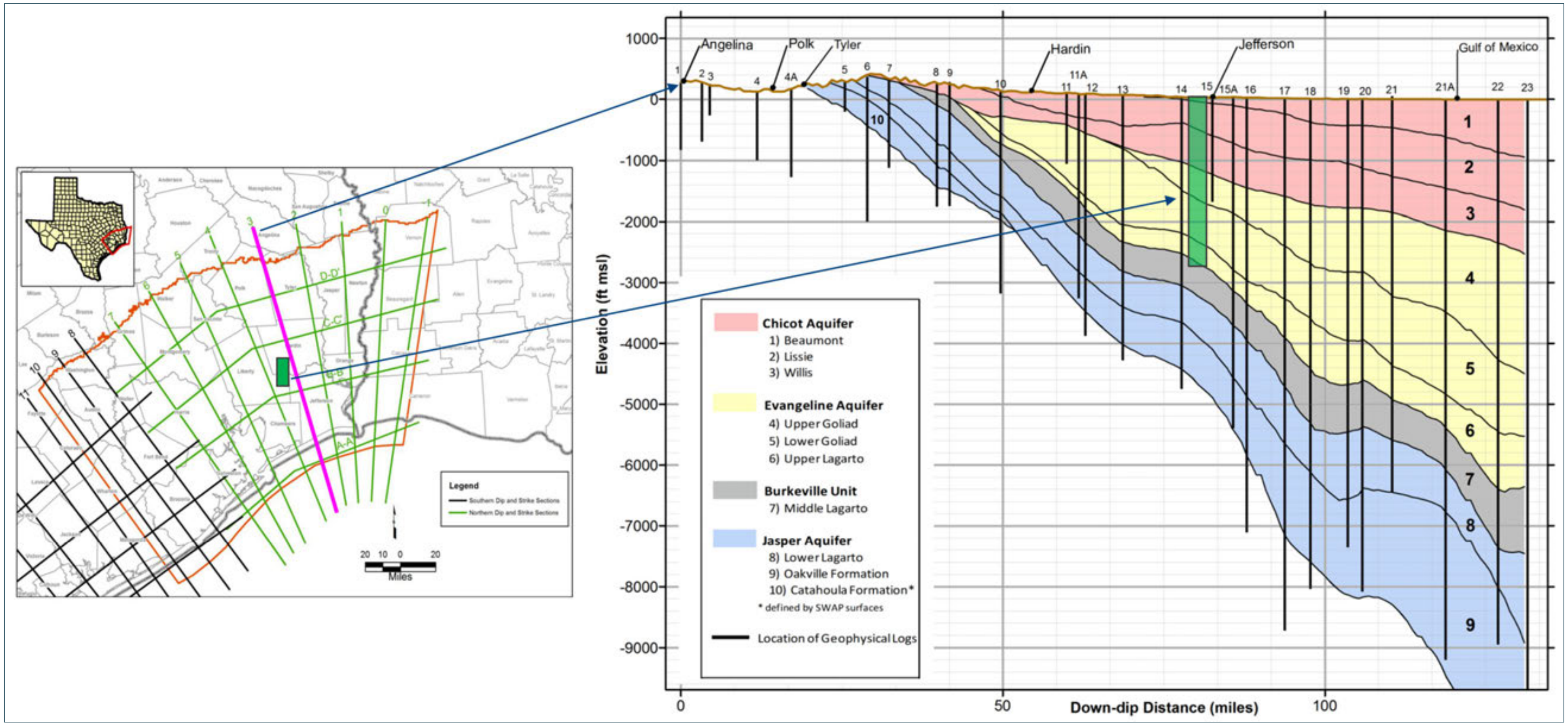

Figure 30: Generalized cross section of Gulf Coast Aquifer formations from a regional cross section near the Pineywoods CCS Hub, as indicated by the green filled rectangle (Young et al., 2012).

B.8.2. Local Hydrological Settings and Base of Deepest USDW

The Chicot Aquifer is the shallowest and main source of fresh water in the project area. The depth of the base of the Evangeline Aquifer varies from 2,700 ft in the south to 1,700 ft in the north in the project area (TWDB interactive map). The shallower part of the Evangeline Aquifer is designated as usable water (Young et al., 2012; Groundwater Advisory Unit of Texas (GAU)). The deeper portion of the Evangline Aquifer contains saline water and may not fall under the category of usable water (**Figure 31**; Young et al., 2012).

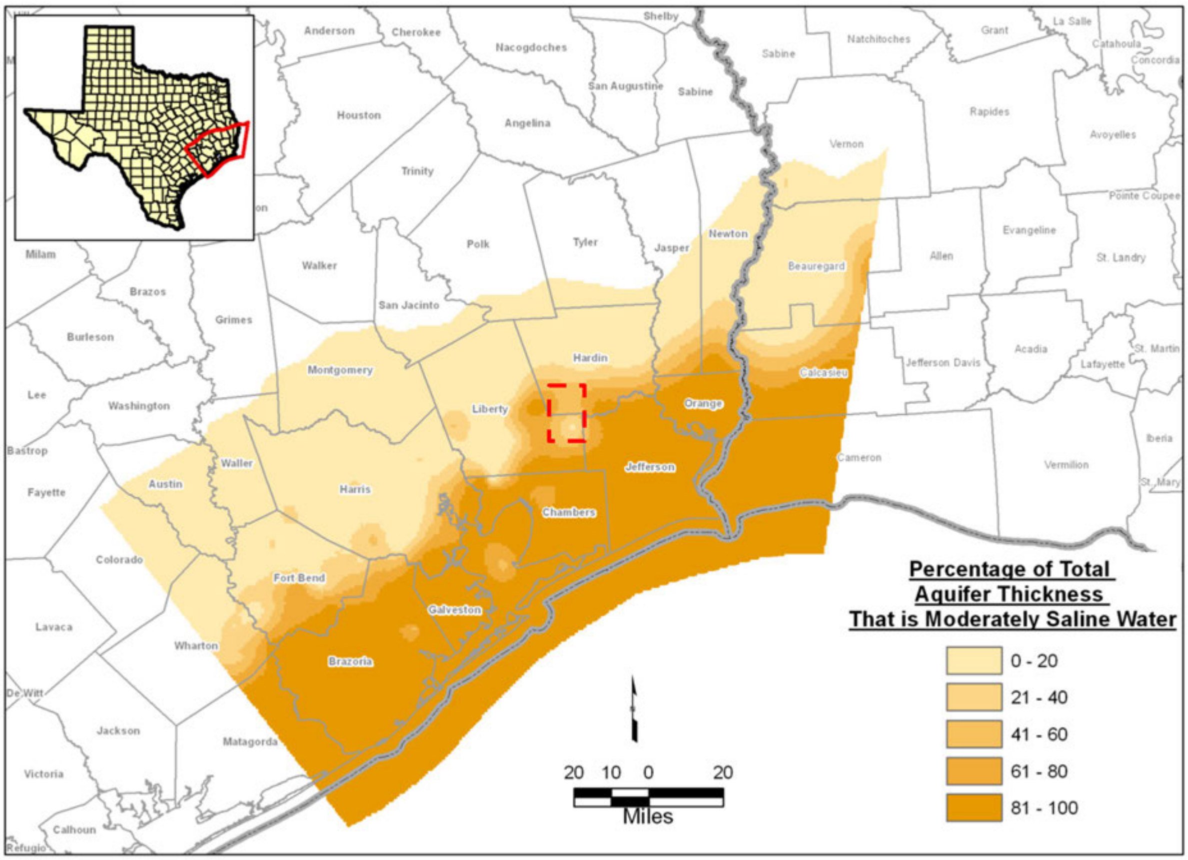

Figure 31: Map showing the percentage of Evangeline Aquifer thickness that has TDS > 3,000 ppm. The project area is shown by the red dashed line (Young et al., 2012).

Groundwater Advisory Unit of Texas (GAU) recommends the deepest sources of water that need to be protected. For the saltwater disposal wells, GAU and EPA requirements are the same. Both require water sources with less than 10,000 mg/L to be protected (GAU, 2023; EPA, 2018). The data for deepest most USDW depths that need to be protected was collected for seven saltwater disposal wells within the project area and is displayed in **Figure 32.** The specified USDW depths that need to be protected vary between 1,200 and 2,200 ft with an average value of 1,486 ft**.**

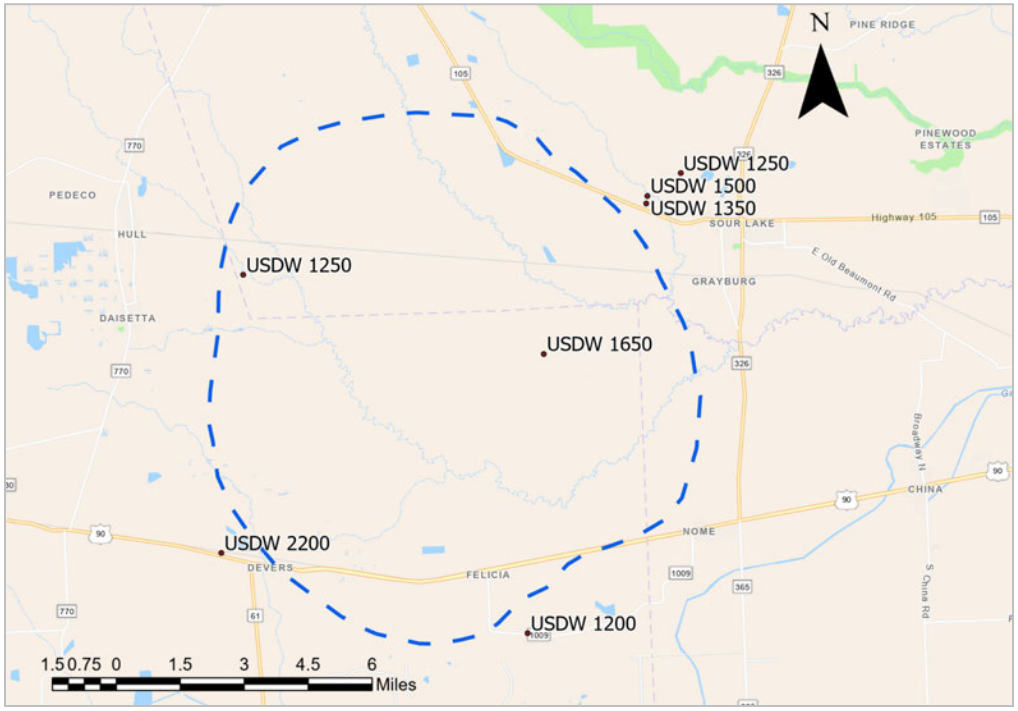

Figure 32: Map showing the depth specified by GAU for usable water to be protected within the AOR for saltwater disposal wells (AoR shown as dashed blue line polygon).

The deep induction resistivity log is also used to get an estimate of the deepest USDW in the project area for a representative well. Most of the well logs in the project area do not cover the strata containing the shallow aquifers including the lowermost USDW. A representative well log from a well (API-29132701) approximately 2.5 miles northwest of PW-2 showing the shallower formations including USDW is shown in **Figure 33**. The criterion based on the use of deep induction log values is used to estimate the lowermost USDW level (LDNR, 2023). The criterion is summarized in **Table 10**. Using the data from the deep induction log, the lowermost USDW in this well is approximately found at a depth of 2,023 ft, indicated in **Figure 33**. A shallower formation approximately at a depth of 1,157 ft also fulfills the criterion of the USDW value, but the deeper value is used as the estimate of USDW at this well location. Subtracting the 20 ft Kelly busing height, subsurface depth of the USDW is approximately 2,000 ft in this well. The deepest USDW for a disposal well outside the AOR was reported at 2,200 ft. Thus, the deepest USDW for the Pineywoods CCS Hub is conservatively estimated at 2,100 ft.

Table 10: Criterion used to estimate the lowermost USDW depth from deep induction logs (LDNR, 2023).

Subsurface Depth Range (ft)	Deep Induction Log Value (ohmm)
0-1000	3 or greater
1000-2000	2.5 or greater
2000-Deeper	2 or greater

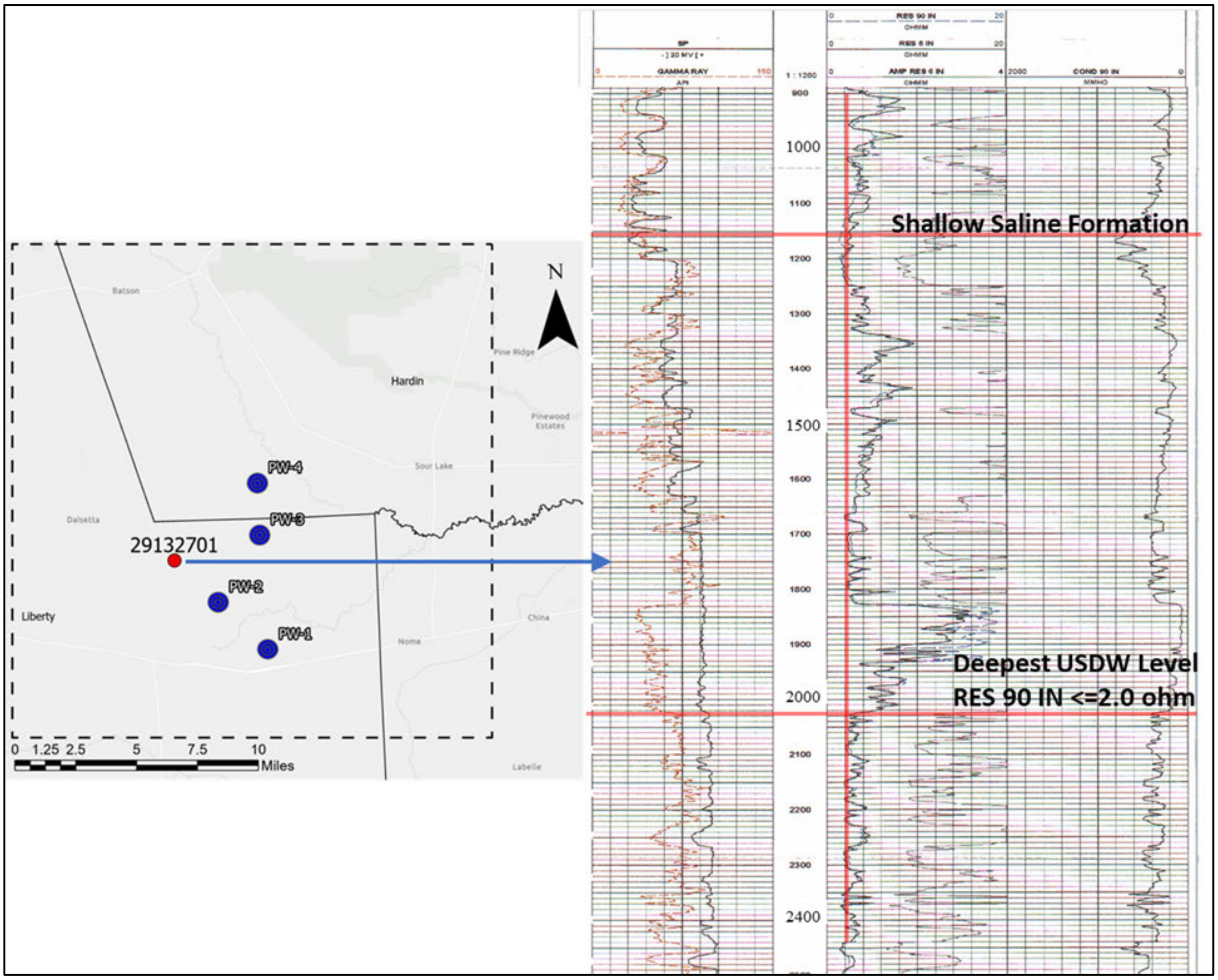

Figure 33: A sample well log (API-29132701) showing the approximate lowermost USDW in Pineywoods project area at a depth of 2,040 ft approximately.

B.8.3. Water Wells within the Pineywoods CCS Hub

There are 129 water wells within the AOR **(Figure 33).** These include 58 domestic wells, 53 rig supply wells, 5 irrigation wells, 4 industrial wells, 3 stock wells, 3 public supply wells, 2 plugged or destroyed wells, and 1 unused well. Borehole depths for these wells range from 29 ft to 988 ft. The majority of the water is extracted from the Chicot aquifer with major flow direction from northwest to southeast (Young et al., 2012).

Public supply well #6160701 provides water for a school and has no yield information. Public supply well #6153703 had a measured yield in 1994 of 902 GPM with 60.5 feet drawdown after pumping 18 hours. The third public supply well, #6153702, had a reported yield of 656 GPM with 40 feet drawdown after pumping 6 hours in 1998, per the Texas Water Development Board Groundwater Database.

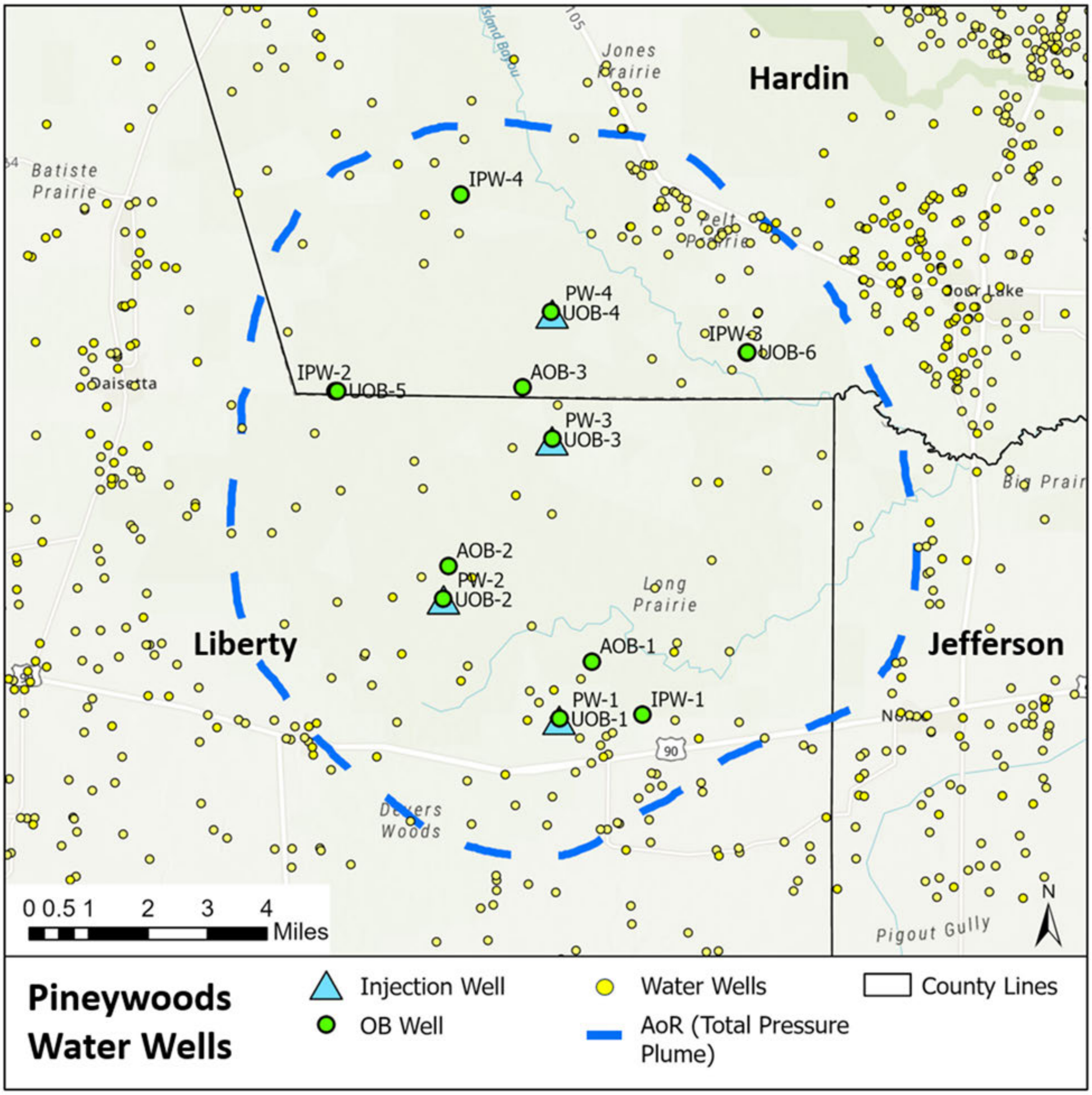

Figure 34: Map of location of groundwater wells in and near AOR.

B.9. Baseline Geochemical Data [40 CFR 146.82(a)(6)]

The USGS produced water database for the Frio Formation was used to estimate a maximum value of salinity as an input to the model. This sampling data provided a salinity value of 113,781 mg/l. **Table 11** shows TDS for the Frio Formation and the confining zones. Fluid samples will be acquired during the construction of injection wells as part of **the Testing and Monitoring Plan** to validate or update these data.

Table 11: Formation water salinities.

Formation	TDS (mg/l)	Source
Margualina A	64,623	USGS National Produced Waters Geochemical Database (2019)
Anahuac	581,55	USGS National Produced Waters Geochemical Database (2019)
Frio	113,781	USGS National Produced Waters Geochemical Database (2019)

Pineywoods CCS, LLC conducted a literature survey to investigate the need to incorporate geochemical interactions into pre-construction computational modeling at the Pineywoods CCS Hub. The results from the literature review indicate that the potential for geochemical alteration of reservoir fluid chemistry and reservoir mineralogy is minimal during the lifetime of the proposed project. The chemical reactions between dissolved CO_2 and reservoir minerals are controlled by their chemical compatibility. As described in **Section B.4,** the Frio reservoir mineralogy is dominated by quartz which is highly unreactive with dissolved CO_2. Refer to **Section B.4** for a detailed mineralogy of the Frio.

Pineywoods CCS, LLC anticipates minimal chemical dissolution of quartz in response to CO_2 and minimal resultant changes in reservoir porosity. Reactive minerals that could react faster with dissolved CO_2 compared to quartz, thereby resulting in mineral dissolution and alteration of reservoir matrix, are minor constituents of the formation and are unlikely to have a large impact during the project. The minerals include potassium feldspar, anorthite, calcite, and pyrite (all minor compared to quartz). In addition, material changes to the reservoir matrix due to dissolution of reactive minerals in the Frio is not expected to pose any risk on CO_2 confinement in the long term as noted by Ilgen and Cygan (2015). In fact, some studies indicate that chemical reaction between dissolved CO_2 and reservoir minerals will lead eventually to trapping CO_2 as a clay or carbonate mineral as noted by Xu et al. (2010).

Ilgen and Cygan (2015) conducted 1D reactive transport modeling in the Frio Formation to investigate the change in the concentration of calcium and strontium ions in brine during CO_2 injection. Ilgen and Cygan (2015) indicated that the injection of CO_2 causes a decline in the brine pH of 3.3 that triggers chemical reactions that led to increasing the pH to its original value of 6.7. Ilgen and Cygan (2015) concluded that the initial increases in calcium and strontium ions are due to calcite dissolution which only counts for 0.0056% of the bulk volume of the formation. The study of reactive transport simulation of 1,000 years did not indicate any changes in potassium feldspar, pyrite, and anorthite volumes after CO_2 injection. The study also showed a precipitation of carbonate and clay minerals such as kaolinite and dolomite. Overall, the change in Frio reservoir porosity after CO_2 injection is only 0.002%.

Xu et al. (2010) conducted a similar study on the Frio formation to investigate the change in brine chemistry after CO_2 injection. They found that calcite and siderite completely dissolved after 150 and 100 years, respectively. However, the dissolution of calcite and siderite causes no risk of CO_2 leakage. The dissolution of calcite and siderite is met by precipitation of ankerite, kaolinite and illite. The study shows that CO_2 gas phase disappears after 500 years, and CO_2 will be trapped as clay and carbonate minerals eventually.

Pineywoods CCS, LLC realizes data assessed to evaluate geochemical interaction in the Frio reservoir is not site-specific, and the need to conduct reactive transport modeling might change after conducting the pre-operational testing and logging. Pineywoods CCS, LLC will acquire sidewall core samples from the injection zone to determine the petrophysical and mineralogical properties of the Frio (See **Pre-Operational Testing Plan**). Mineralogical analysis will determine the type percent composition of potentially reactive minerals within the Frio at the injection locations. Pineywoods CCS, LLC will also gather fluid samples from the injection zone and shallower zones at a minimum to establish a baseline geochemical description of reservoir fluids. Collected fluid samples will be used to develop synthetic brine compositions to run core flooding studies to assess possible interactions between injected CO_2, reservoir matrix, and in-situ brine. Fluid samples will be analyzed to determine the changes in brine chemistry before and after CO_2 injection. Reservoir samples subjected to geochemical testing will be imaged pre- and post-testing to assess changes in the rock matrix. If Pineywoods CCS, LLC determines geochemical changes to reservoir rock or fluids are prominent as concluded from these tests, a reactive transport model will be built in GEM and coupled with the current reservoir model to assess long term fate of injected CO_2 as it is related to mineralogical changes in the reservoir. For reference, initial fluid chemistry data was collected from the USGS National Produced Waters Geochemical Database as shown in **Table 12.**

Table 12: Formation water properties (USGS, 2016).

Attribute/ion	Frio	Anahuac	Margualina A
pH	7.4	6.7	5.3 mg/L
Ba^{2+}	73 mg/L	8 mg/L	-
HCO_3^-	181 mg/L	25 mg/L	600 mg/L
Ca^{2+}	2872 mg/L	4744 mg/L	4870 mg/L
Cl^-	64934 mg/L	35600 mg/L	39000 mg/L
K^+	178 mg/L	-	-
Mg^{2+}	642 mg/L	243 mg/L	336 mg/L
Na^+	39040 mg/L	17284 mg/L	19456 mg/L
SO_4^{2-}	12 mg/L	259 mg/L	194 mg/L

B.10. Site Suitability [40 CFR 146.83]

The geologic site characterization of the Pineywoods CCS Hub along with information assembled by other studies show that the project area provides a geologically favorable setting for safe, long-term storage of CO_2. The primary CO_2 injection interval within the Oligocene strata is the Lower Frio Formation that contains a series of interbedded sand and shale intervals. The well log data used in the site characterization show favorable attributes for the storage zone and caprock combination in the Pinewoods CCS Hub. The Lower Frio is relatively cleaner and has good porosity and permeability in the Pineywoods CCS Hub and is also reported in literature for other nearby areas (Hovorka, 2009).

The Frio Formation has previously demonstrated the capability for geologic sequestration of CO_2 in the Frio Pilot Test Site, which is located approximately 20 miles southwest of PW-1 (Hovorka, 2009). In the Frio Pilot Test, extensive testing of the Frio Formation (storage zone) and Anahuac Formation (primary seal) was conducted. The lab and field test data of the Frio Pilot Test exhibited a good storage zone and primary seal combination (Hovorka, 2009: Jung, 2017). The Upper Frio, which is not used for storage, is shalier than the storage zone of the Lower Frio. The Upper Frio is expected to provide additional dampening of the rising CO_2 plume before it can reach the primary seal, the Anahuac Formation.

The Anahuac Formation is a marine shale and deposited in a complete transgressive - regressive cycle (Galloway, 2008). The average thickness of the Anahuac Formation is several hundred feet in the Pineywoods CCS Hub. A very high capillary entry pressure of more than 3,500 psi also demonstrates that it is a good sealing unit (Hovorka, 2009). There are multiple known good regional marine shales in the shallower Miocene strata that may act as secondary and tertiary seals (Hovorka, 2009).

Multiple legacy oil and gas wells and faults are present in the Pineywoods CCS Hub. These may act as leakage pathways for the stored CO_2. Therefore, the locations of the injection wells were selected to avoid the known faults and higher density areas of legacy oil and gas wells. Moreover, the observation well locations were selected in such a manner that the CO_2 plume front can be tracked before it reaches the known faults. Therefore, through rigorous monitoring, the leakage risk through faults and legacy oil and gas wells will be minimized.

A very thick regional shale Vicksburg forms the bases of the Frio Formation. Therefore, leakage risk of Brine or CO_2 to the deeper formation is expected to be minimal.

The characteristics of the injection and confining units suggest that the Frio Formation is compatible with the long-term storage of CO_2. Highly porous and permeable sandstones, overlain and underlain by thick intervals of proven sealing units, ensure the prevention of vertical migration of CO_2 out of the Frio Formation. Additionally, the regional continuity of the primary and secondary confining units demonstrate that the CO_2 plume will be confined to the Frio injection interval. Through rigorous monitoring, the leakage risk from the known faults and legacy oil and gas wells will be minimized.

C. INJECTION WELL CONSTRUCTION DESIGNS

The injection wells have been designed to accommodate the mass of CO_2 that will be delivered to the storage site, considering key characteristics of the CO_2 storage reservoir that affect the well design. This section illustrates the comprehensive analysis performed to comply with and exceed the federal and state Class VI UIC well standards regarding the design of the casing, cement, and wellhead [40 CFR 146.86(a); 16 TAC 5.203(e)].

C.1 Wellhead Injection Pressure

SLB's *PIPESIM* software was used to conduct a nodal analysis to determine the feasibility of CO_2 injection through 5.5-inch tubing for the CO_2 injection wells. The analysis assumes an expected wellhead (injection) pressure of about 1,500 psia (**Section D.4** of the **Application Narrative**).

The nodal analysis for PW-1 and PW-3 was designed for a long string casing of 9.625-inch 53 lb/ft L80 LTC thread set to a total depth of 6,900 feet and with a 5.5-inch 17lb/ft injection tubing string set at 5,950 feet. The nodal analysis for PW-2 and PW-4 was designed with the same casing program, but the tubing was set to 6,860 feet and installed with two sliding sleeves to isolate the upper and lower injection interval. Additionally, when both sleeves are open, the flow profile is equivalent to the nodal analysis case with no sliding sleeves (i.e., full access to all of the injection perforations). The injection tubing strings in all four injection wells will use L-80 steel and 13 chrome type (13Cr-L80). Design parameters from the geologic model are shown in **Table 13** below. The schematics for the casing nodal analysis of both designs are shown in **Figure 35.**

Table 13: Zonal inputs for nodal analysis.

	Top (ft)	Bottom (ft)	Mid Point (ft)	Thickness (ft)	Pressure (psi)	Average Permeability (md)	Reservoir Temp (°F)
Anahuac (Confining Zone)	4,712	4,984	4,848	272	2,191	10e-5	132
Middle Frio (Upper Injection Interval)	5,953	6,384	6,168	431	2,868	219	151
Lower Frio (Lower Injection Interval)	6,384	6,815	6,599	431	3,068	219	157

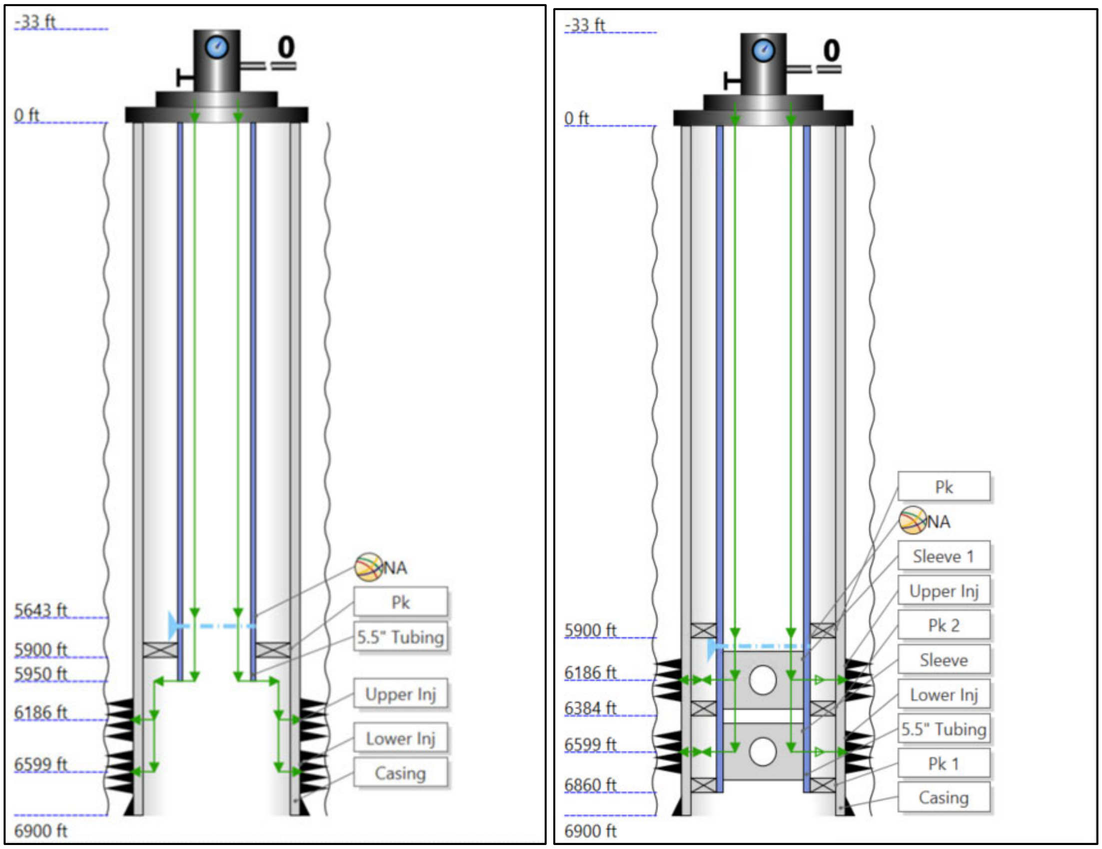

Figure 35: (A) Nodal analysis design schematic with no sliding sleeves (PW-1 and PW-3), (B) Nodal analysis design schematic with sliding sleeves (PW-2 and PW-4).

At an injection rate of 1.25 MMt/y, the resulting wellhead pressure (no sliding sleeves or both fully open) is expected to be 1,114 psia, which conforms to the expected delivery pressure (**Figure 36**). If the injection rate momentarily spikes, an injection rate of 1.50 MMt/y results in a wellhead pressure of 1,171 psia (**Figure 37**).

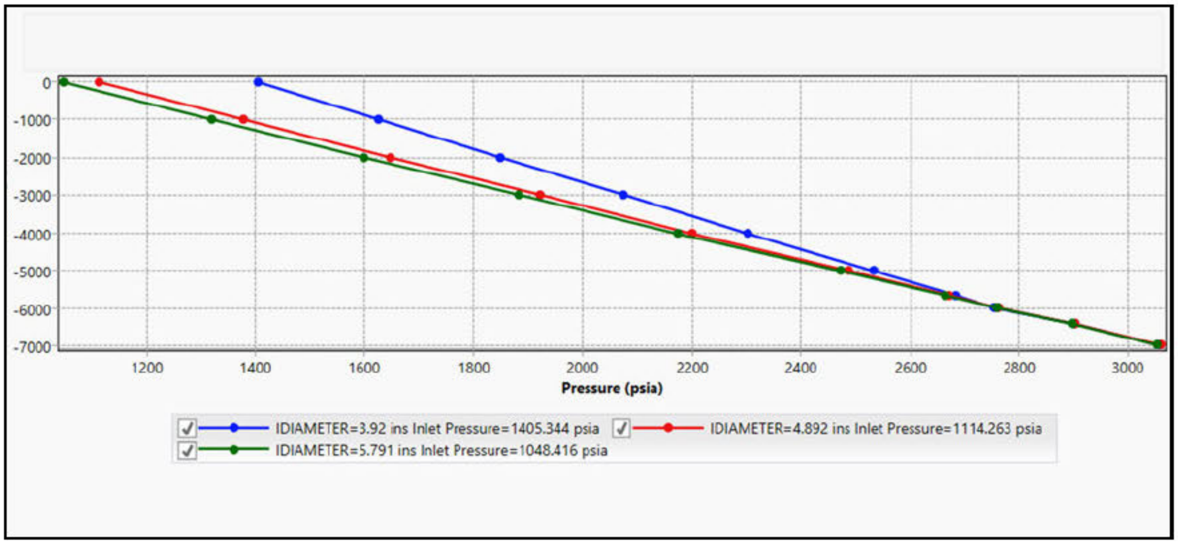

Figure 36: Wellhead pressure at 1.25 MMt/y (PW-1 and PW-3 with no sliding sleeves or PW-2 and PW-4 with both sleeves fully open).

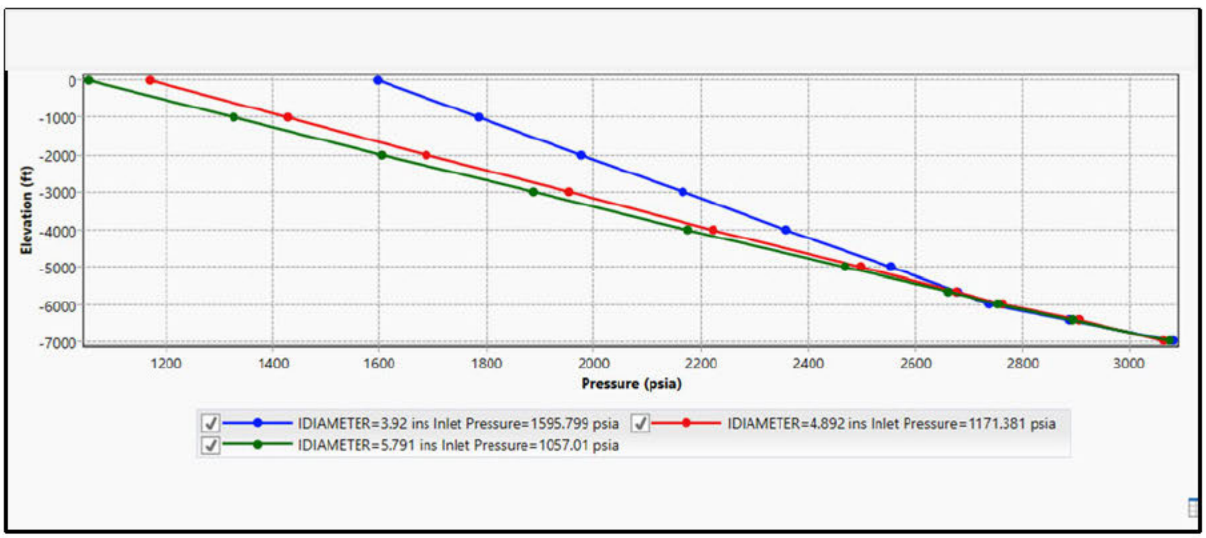

Figure 37: Wellhead pressure at 1.50 MMt/y (PW-1 and PW-3 with no sliding sleeves or PW-2 and PW-4 with both sleeves fully open).

In a situation where the sleeve accessing the lower injection zone is closed, and only the upper injection zone is open to injection, the tubing is still able to support an injection rate of 1.25 MMt/y, with a wellhead pressure of 1,152 psia (**Figure 38**). However, if the upper injection sleeve is closed, and only the lower injection sleeve is open to injection, an injection rate of 1.25 MMt/y results in a wellhead pressure of 1,189 psia (**Figure 39**). Maximum injection wellhead pressure is set forth in **Section D.5**.

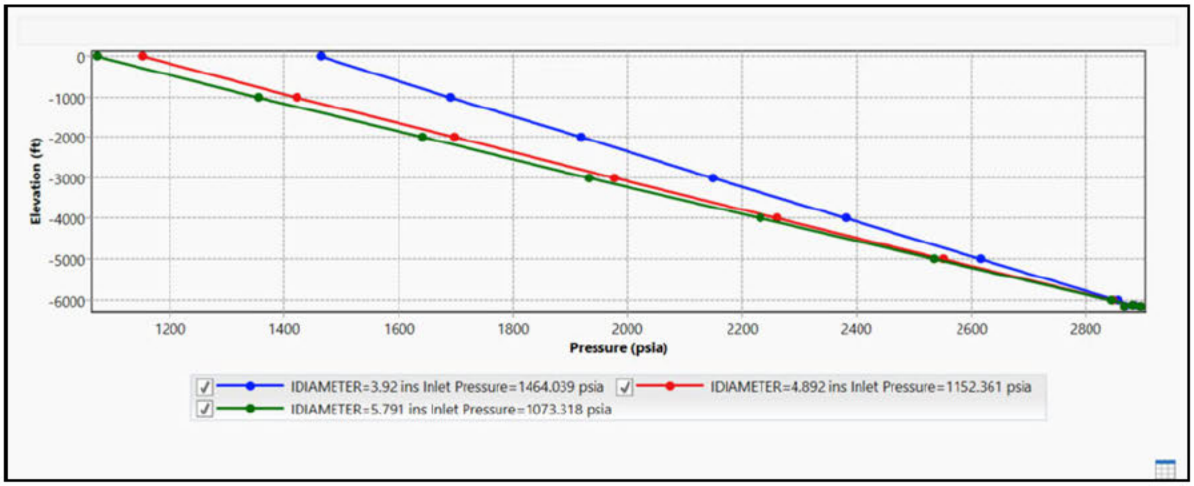

Figure 38: Upper injection zone only of PW-2 and PW-4, wellhead pressure at 1.25 MMt/y.

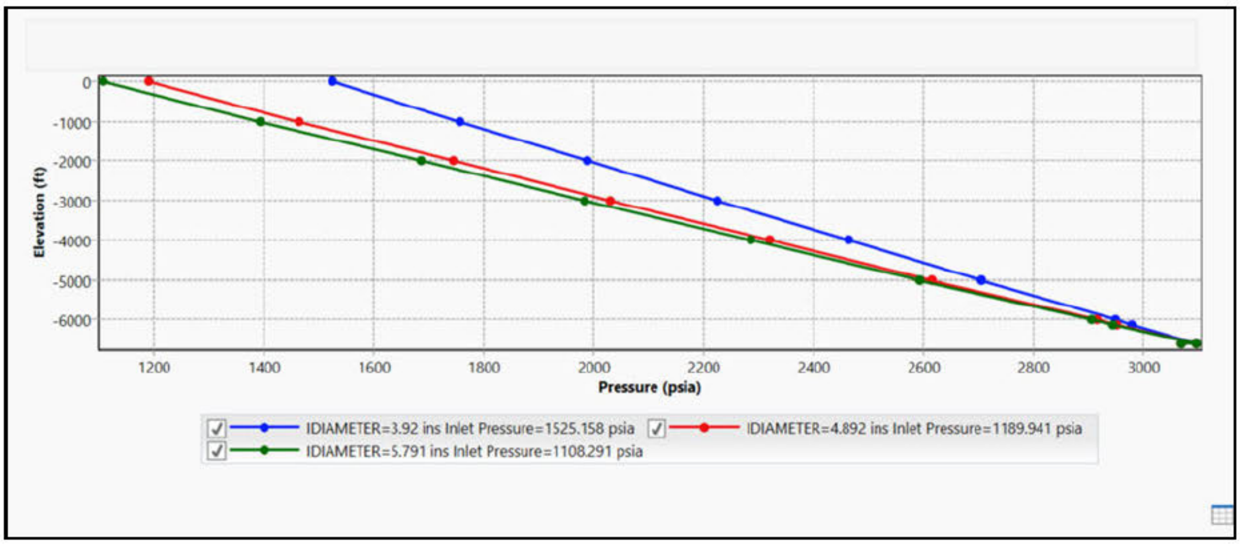

Figure 39: Lower injection zone only of PW-2 and PW-4, wellhead pressure at 1.25 MMt/y.

The sliding sleeves provide an additional benefit of the ability to control the amount of flow into each zone by opening the sliding sleeve partially. PipeSIM modeling was conducted to determine the associated wellhead pressures with partially open sliding sleeves. Baker Hughes HCM-A hydraulically operated sliding sleeves can be set to fully closed, 10% open, 20% open, 30% open, 40% open, 50% open, 60% open, and fully open. PipeSIM does not allow for sliding sleeves to be set to partially open; therefore, the partially open setting was approximated by modeling a downhole choke to control the flow area just before the top sliding sleeve. A fully open sliding sleeve has the equivalent flow area of open-ended tubing. Therefore, a sliding sleeve set to 10% open is equivalent to having 10% of the open-ended tubing flow area, or a choke bean equivalent to 10% of the flow area. Equivalent flow areas were calculated for each setting and modeled in PipeSIM. PW-4 was used as flowing pressures were the lowest when the sleeves were fully open, and the largest impact on flowing pressures could be seen. By approximating both sliding sleeves set to 10% flow area, the corresponding wellhead pressure at PW-4 for 1.25 MMt/y was 1,122 psia **(Figure 40)**. The same scenario at the maximum instantaneous rate of 1.5 MMt/y resulted in a wellhead pressure of 1,183 psia (**Figure 41**).

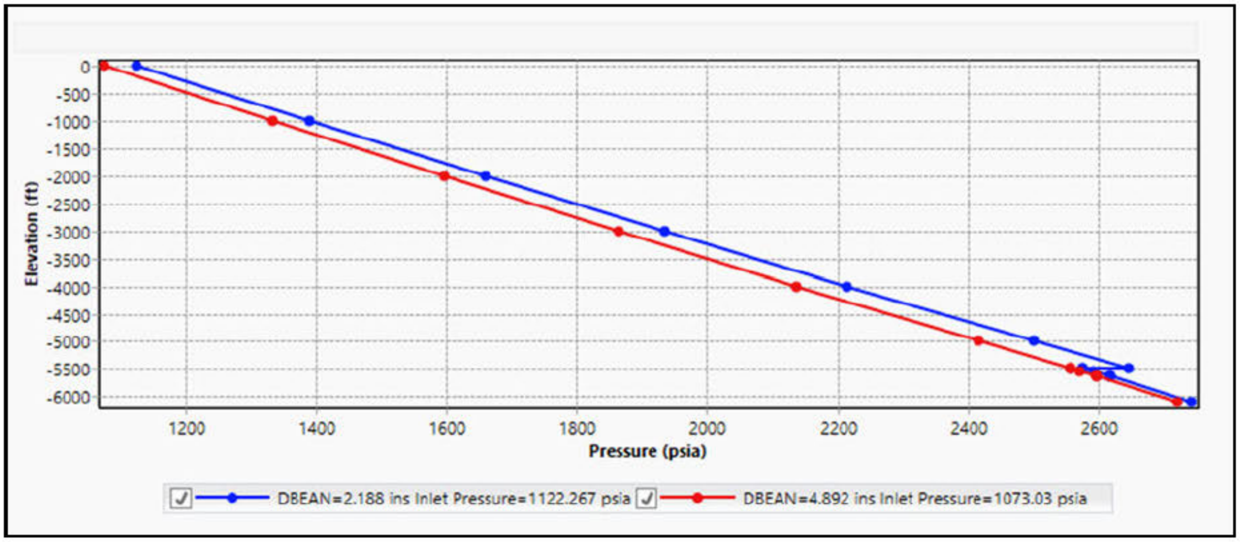

Figure 40: Both sleeves on PW-4 at 10% open, wellhead pressure at 1.25 MMt/y.

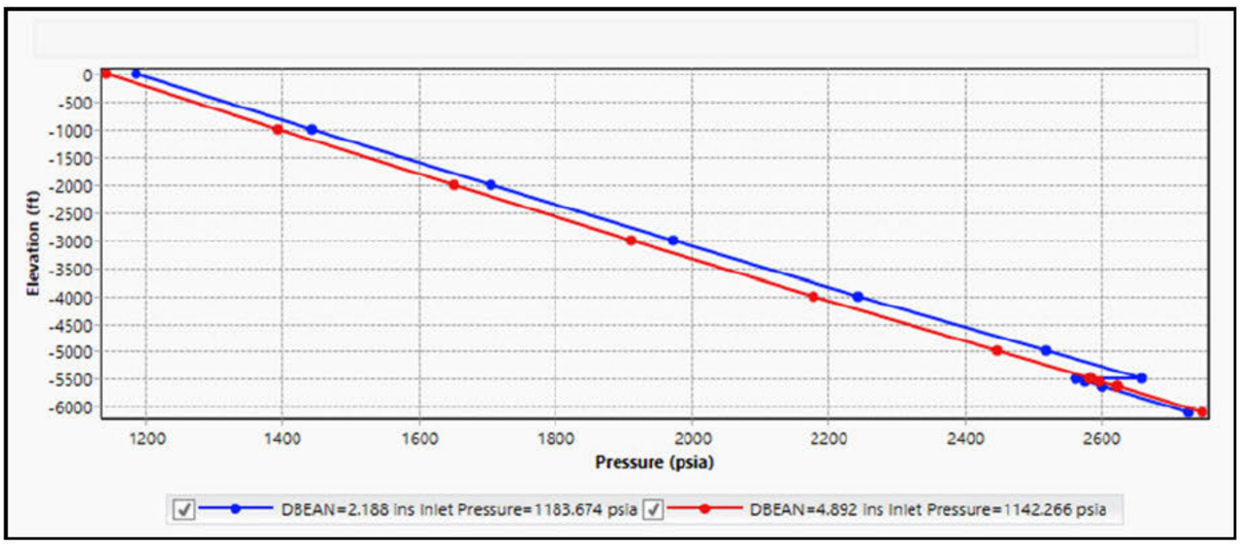

Figure 41: Both sleeves on PW-4 at 10% open, wellhead pressure at 1.5 MMt/y.

C.2 Casing Program

Nodal analysis aided in the development of an injection well design to accommodate a 5.5-inch outer diameter (OD) tubing. Additionally, the injection wells have been designed to accommodate the concentric casing sizes required to isolate the injection reservoir from USDWs. Material for the casing was selected to be appropriate for the fluids and stresses encountered within the well (40 CFR 146.86(b)(1)). For instance, casing strings that will be exposed to injected CO_2 will be

13Cr-L80 steel, which is resistant to corrosion from CO_2.

Lab results have shown the corrosion rate of 13Cr steel in the high-temperature steam environment was less than 0.04 mm/a (Guoqing Xiao, 2020), which is sufficient to retard metallurgical corrosion should moisture or formation fluid come into contact with the CO_2. The entire injection tubing string will be comprised of 13Cr-L80 steel. Similarly, the 9.625-inch-long string casing will be constructed of 13Cr-L80 steel through the injection zone to above the confining zone.

Alternatively, coated tubing has shown adequate resistance to corrosion (Tuboscope, 2022). Actual installation will depend on availability, and the UIC Program Director will be notified prior to installation.

In areas where the risk of CO_2 corrosion is not a concern, J-55 mild steel will be utilized. Lithology of the storage reservoir's injection and confining zones is discussed in **Section B.4,** and reservoir fluid characteristics are discussed in **Section B.9**. The anticipated composition and temperature of the CO_2 stream, discussed in **Section D.2** and **Table 25,** is consistent with that of the U.S. CO_2-EOR industry, where mild steel is used. Constructing the wells with 13Cr steel components or coatings should exceed the protection requirements and be consistent with Guoqing Xiao's data (2020).

Casing stresses and loadings were modeled using SLB's Tubing Design and Analysis (TDAS) software. To ensure sufficient structural strength and mechanical integrity throughout the life of the Pineywoods CCS Hub, stresses were analyzed and calculated according to worst-case scenarios, and tubular specifications were selected accordingly. Minimum design factors presented in **Table 14**, **Table 15**, and **Table 16** below summarize the results of this stress analysis. The burst, collapse, and tensile strength of each tubular specification was calculated according to the scenarios defined below and was dependent on fracture gradients, mud weight, depths, and minimum safety factors.

As demonstrated, these safety factors are sufficient in the worst-case scenarios to prevent migration of fluids into or out of USDWs or unauthorized zones. The casing and tubing materials are designed to be compatible with the fluids encountered and the stresses induced throughout the sequestration project. SLB Integrated Drilling Systems design standards were incorporated for the casing design calculations, and SLB Completions group standards were incorporated for the tubing design calculations.

Table 14: Minimum design factors.

Load	Casing Design Criteria	Tubing Design Criteria
Burst	1.1	1.1
Collapse	1.1	1.1
Tension	1.6	1.4
Compression	1.2	1.2
VME	1.25	1.25

The casing installed in any well should be designed to withstand collapse loading based on the following assumptions:

1. The hydrostatic head of the drilling fluid in which the casing is run acts on the exterior of the casing at any given depth;
2. Subject to the casing being 1/3 evacuated;
3. The production casing is completely evacuated;
4. The effect of axial stresses on collapse resistance shall be considered; and
5. The effect of temperature deration and casing wear shall be considered.

Any casing/liner that creates an annular space with the production tubing shall be treated as a production casing/liner. The casing installed in any well shall be designed to withstand tensile loading based on the following assumptions:

1. The weight of casing is its weight in air; and
2. The tensile strength of the casing is the yield strength of the casing wall or of the joint, whichever is the lesser.

The following additional assumptions were made during the design process for the injection wells:

1. A 5% casing wear due to bottomhole assembly (BHA) rotation is assumed on all casing design segments with consecutive hole sections;
2. Wall tolerance of 87.5% is assumed per API standards;
3. Temperature deration is considered on the design of the 9-5/8-inch casing string; and
4. The 9-5/8-inch casing is being proposed and engineered to comply with a casing designed to pass a 1/3 evacuation loading on collapse.

If the casing recommended is not available, final casing selection would be based on what other technical options are currently available and what might be in stock at a U.S.-based tubular suppliers' inventory. The minimum criteria for an alternate design would be to exceed standard design criteria.

Table 15: Surface casing load scenarios evaluated showing the design factors for each scenario.

Load Case	Pressure Profile		Temperature Profile	Wear Percentage	Minimum Design Factor				
					Pressure		Axial		Triaxial
	Internal	External			Load	Factor	Load	Factor	Factor
Green Cement Pressure Test	9.5 ppg + 986 ppg	Cement	Static	5	Burst	3.13	Tension	3.58	3.39
As Cemented	9.5 ppg	Cement	Static	5	Collapse	3.15	Compression	4.24	7.01
1/3 Evacuation - 7300 ft	1/3 Evacuation	9.5 ppg	Static	5	Collapse	1.13	Compression	2.44	2.68
Pressure Test - 2500 ft	9.5 ppg + 500 psi	Pore pressure	Static	5	Burst	1.48	Tension	3.44	1.58
100 bbl Gas Kick - 7300 ft	Gas kick	Pore pressure	Circulating	5	Burst	2.48	Tension	8.18	2.67
1/3 Replacement - 7300 ft - Circulating	1/3 Replacement	Pore pressure	Circulating	5	Burst	2.43	Tension	8.03	2.62
1/3 Replacement - 7300 ft - Static	1/3 Replacement	Pore pressure	Static	5	Burst	2.44	Tension	4.20	2.72

Table 16: Long-string casing load scenarios evaluated showing the design factors for each scenario.

Load Case	Pressure Profile		Temperature Profile	Wear Percentage	Minimum Design Factor				
					Pressure		Axial		Triaxial
	Internal	External			Load	Factor	Load	Factor	Factor
Green Cement Press Test	9.5 ppg + 1734 psi	Cement	Static	5	Burst	3.96	Tension	3.54	3.23
As Cemented	9.5 ppg	Cement	Static	5	Collapse	3.80	Compression	4.56	4.72
Full Evacuation - Static	Full Evacuation	9.2 ppg	Static	5	Collapse	1.14	Compression	2.74	1.91
Pressure Test - 4264 ft	9.2 ppg + 3000 psi	Pore pressure	Static	5	Burst	2.08	Tension	3.49	2.17

C.3 Casing Summary

Per 16 TAC 5.203(e)(1)(B), casing for injection wells at the Pineywoods CCS Hub will be in compliance with requirements at 16 TAC 13.3(a)(4).

The injection well design was analyzed for the PW-1 location. This location is the deepest and will experience the highest stresses of all the injection wells. The design will be mirrored in PW-2, PW-3, and PW-4 and will include the following casing strings: a 20-inch-diameter conductor casing string set at a depth of approximately 60 feet below ground surface (BGS) inside a 26-inch borehole; a 13.375-inch diameter surface casing string set at a depth of approximately 2,500 feet below ground surface (BGS) inside a 17.5-inch borehole; a 9.625-inch diameter long casing string set at the top of the Vicksburg formation (a depth of approximately 7,300 feet BGS at PW-1) inside a 12.25-inch borehole; and a 5.5-inch diameter deep (injection) tubing string set at approximately 6,100 feet BGS, and be equipped with a packer to isolate the tubing annulus. PW-2 and PW-4 will have the same construction, however the tubing will be run to 6,860 feet BGS and equipped with two sliding sleeves run in series, corresponding with the two injection zones. All casing strings will be cemented to the surface. The borehole diameters are considered conventional for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement seal can be emplaced along the entire length of the casing string. **Table 17** summarizes the casing program for the injection wells**. Table 18** summarizes properties of each casing material. Each section of the well is discussed in a separate section below.

Table 17: Summary of the borehole and casing program for the injection wells.

<table>
<tr><th>Casing String</th><th>Casing Depth (Feet BGS)</th><th>Borehole Diameter (in.)</th><th>Casing Outside Diameter (in.)</th><th>Casing Material (weight/grade/ connection)</th><th>Coupling Outside Diameter (in.)</th></tr>
<tr><td>Conductor</td><td>60</td><td>26</td><td>20</td><td>78.60 lb/ft, Welded</td><td>NA</td></tr>
<tr><td>Surface</td><td>2,500</td><td>17.5</td><td>13.375</td><td>61 lb/ft, J-55, STC</td><td>14.375</td></tr>
<tr><td rowspan="2">Long String</td><td>4,500</td><td rowspan="2">12.25</td><td>9.625</td><td>47 lb/ft, L-80, LTC</td><td>10.625</td></tr>
<tr><td>4,500-7,300</td><td>9.625</td><td>47 lb/ft, CR13-L80, LTC</td><td>10.625</td></tr>
</table>

Table 18: Properties of well-casing materials.

Casing String	Casing Material (weight/grade/ connection)	Casing Outside/Inside/Drift Diameter (in.)	Burst (psia) Plain End	Collapse (psia)	Joint Tensile Strength (1,000 psia)
Conductor	78.60 lb/ft, Welded	20 / 19.250 / 19.063	1,150	320	809 (Body)
Surface	61 lb/ft, J-55, STC	13.375 / 12.515 / 12.359	3,090	1,520	595
Long String	47 lb/ft, L-80, LTC	9.625 / 8.681 / 8.525	6,870	4,760	893
	47 lb/ft, CR13-L80, Premium Connection	9.625 / 8.681 / 8.525	6,870	4,760	1,086
Tubing	17 lb/ft, CR13-L80 or Coated L80, Premium Connection	5.5 / 4.670 / 4.545	10,560	11,160	530

C.3.1 Conductor Casing

The conductor casing consists of 20-inch diameter mild steel and provides the stable base required for drilling activities in unconsolidated sediment. Depending on wellsite conditions, this can be drilled and installed or driven directly. This section of casing is also cemented in place.

C.3.2 Surface Casing

The surface casing is 13.325-inch diameter 61-lb/ft J-55 pipe with short thread couplings (STCs). The metallurgy of this casing string is carbon steel. Surface casing is to be cemented to surface, isolating the USDWs through which the string extends. Following the cement setting, a bond log is run to ensure a sufficient seal to prevent the migration of fluid into USDWs.

C.3.3 Long-String Casing

The long-string casing will be 9.625-inch diameter pipe composed of two sections. The long-string casing is required to extend from the surface to the injection zone (40 CFR 146.86(b)(3)). The uppermost section will be L-80 47-lb/ft carbon steel pipe with long thread couplings (LTCs); the lower section will be a corrosion-resistant alloy (e.g., 13Cr-L80 steel) having strength properties equivalent to or better than L-80 47-lb/ft pipe with premium connections. The transition will be targeted for approximately 4,500 feet MD or 500 feet above the targeted caprock. A DTS/DAS fiber optic cable will be run outside the casing from surface into the confining unit and cemented in place with the casing.

C.4 Tubing

The tubing connects the injection zone to the wellhead and provides a pathway for storing CO_2. This design utilizes 5.5-inch 17 lb/ft 13Cr-L80 steel or coated tubing, which resists corrosion from the injected fluid. At a depth of approximately 5,950 feet, a packer will be set to isolate injection zones from the tubing-casing annulus. At the end of the tubing string, a landing nipple, or “no-go” tool will be run. This will allow a plug to be set inside the tubing at this depth and the packer to be released in order to remove the tubing string if needed.

In PW-2 and PW-4, sliding sleeves will be utilized, across the injection zones, in the tubing string. These sleeves will enable two injection zones to be open or closed, independent of each other, to accommodate fluctuations in injection rates due to CO_2 availability. A packer will be placed between the sleeves at a depth of 6,384 feet to isolate injection.

Tandem pressure/temperature gauges will be hung in the tubing string immediately above the top packer. Considering the anticipated formation pressure, temperature, and stress, the grade of tubing was selected with the API specifications outlined in **Table 20**, which includes the calculated safety factors. These safety factors represent sufficient quality standards to preserve the integrity of the injected fluid, the injection zone, and above USDWs. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in **Section C.5.1** below in accordance with 40 CFR 146.88(c).

C.5 Packer Details

The injection wells will utilize a minimum of one packer. The packers will be used to isolate the tubing annulus and, in the case of PW-2 and PW-4, used to isolate the injection intervals. The packer system will consist of Baker Hughes 3-foot long, 8.218" OD, 6.0" ID, Model F Permanent Packer with a BMS-S210 13Cr80 Mandrel and 70hd Nitrile Element System rated for pressures up to 5,000 psi or similar packer. The uppermost packer will be connected to a 10 foot-long, 6.250" OD, 4.875" ID model G-22 locator type seal assembly for easy workover operations. Both the packer and locator seal assembly with feature VAM couplings and will be comprised of 13CR80 alloy. Please refer to **Table 20** for modelled load scenarios and **Table 19** for specifications of the packer. The annulus between the tubing and long-string casing will be filled with noncorrosive fluid described in further detail within the annular fluid program in **Section C.6.1** below.

Table 19: Packer details.

Item	Setting Depth (Approximate)	Tensile Strength (psi)	Burst Strength (psi)	Collapse Strength (psi)	Material (weight/grade/connection)
Packer (Baker Hughes Model F Permanent Packer)	5900-5910	-	7,000	5,000	13Cr80/ VAM Coupling

Table 20: Tubing load scenarios evaluated showing the design factors for each scenario.

Load Case	Pressure Profile		Temperature Profile	Wear Percentage	Minimum Design Factor				
					Pressure		Axial		Triaxial
	Internal	External			Load	Factor	Load	Factor	Factor
As Run	10 ppg	10 ppg	Static	5	-	-	Tension	4.54	4.04
Tubing Pressure Test	10 ppg + 5,000 psi	10 ppg	Static	5	Burst	1.51	Tension	2.74	1.58
Installed Load	10 ppg	10 ppg	Static	5	-	-	Tension	4.54	4.04
Annular Pressure Test	10 ppg	10 ppg + 1500 psi	Static	5	Collapse	3.49	Tension	5.73	2.80
Full Evacuation - Static	Full Evacuation	10 ppg	Static	5	Collapse	1.46	Compression	3.66	2.02
Gas Shut-In - Cold	8.95 ppg	10 ppg	Static	5	Collapse	13.97	Tension	4.42	3.94
Gas Shut-In - Static	8.95 ppg	10 ppg	Static	5	Collapse	13.97	Tension	4.42	3.94
Surface Tubing Leak - Static	8.95 ppg	10 ppg + 2665 psi	Static	5	Collapse	1.46	Compression	3.08	1.81

C.6 Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. The conductor, surface casing, and deep casing will be cemented to the surface in accordance with requirements at 40 CFR 146.86(b)(3) and exceeds requirements of 16 TAC 3.13. The proposed cement types and quantities for each casing string are summarized in **Table 21**.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement completely surrounds the casing along the entire length of pipe. The casing string will be centralized to attempt a minimum of 75% standoff. The actual hole trajectory will be input into the cementing service company's mud removal software to optimize centralizer placement. Centralizers will be placed either over the connections or at mid-joint using stop-rings as appropriate. It is estimated that approximately 150 or more centralizers will be used depending upon the hole trajectory. Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing, and a float collar will be run on the top of the bottom joint of casing.

The 9.625-inch long-string casing is to be cemented to the surface and can be completed in a single stage. The long-string casing will be cemented with a lead of 65/35 Poz mix followed by EverCRETE or similar CO_2 resistant tail cement. The transition will be targeted at an approximate depth of 4,500 feet. Cement-bond logs will be run and analyzed for each casing string.

Table 21: Cementing program.

Casing String	Casing Depth (ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (ft)	Cement
Conductor Casing	60	26	20	0-60 (cemented to surface)	Class A with 2% $CaCl_2$ (calcium chloride) and 0.25 lb/sack cell flake; cement weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 49 sacks.
Surface Casing	2,500	17.5	13.325	0-2,500 (cemented to surface)	Class A with 2% $CaCl_2$ and 0.25 lb/sack cell flake; weight: 15.6 lb/gal; yield: 1.20 ft^3/sack; quantity: 1,525 sacks.
Long Casing String	7,300	12.25	9.625	4,500-7,300 0-4,500 (cemented to surface)	Tail: EverCRETE CO_2- resistant cement (or similar); weight: 15.92 lb/gal; yield: 1.08 ft^3/sack; quantity: 812 sacks. 65/35 Pozmix with 2% gel; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 1,780 sacks.

*See acronym list for definition of abbreviations used in this table.

C.6.1 Annular Fluid

The annular space above the packer between the 9.625-inch long-string casing and the 5.5-inch injection tubing will be filled with fluid to provide a positive pressure differential to stabilize the injection tubing and inhibit corrosion. Annular fluid pressure at the surface will be controlled to remain between 250 and 500 psia during injection operations (See **Section C.2 of the Testing and Monitoring Plan** for a full description of the injection well annulus monitoring system). Added to the hydrostatic pressure of the fluid column, this will ensure that the annular pressure downhole will be greater than injection pressure.

The annular fluid will be fresh water treated with additives and inhibitors including a corrosion inhibitor, biocide (to prevent growth of harmful bacteria), and an oxygen scavenger. The fluid will be mixed onsite from good quality (clean) freshwater and liquid and dry additives, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of the type of fluid will depend on availability.

Example additives and inhibitors are listed below along with approximate mix rates:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars [i.e., casings, tubing]) – 10 gal per 100 bbl of packer fluid;
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbl of packer fluid;
- Spec-cide 50 (biocide) – 1 gal per 100 bbl of packer fluid; or
- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbl of packer fluid.

These products were recommended and provided by Tetra Technologies, Inc., of Houston, Texas. Actual products may vary from those described above.

C.6.2 Wellhead

The wellhead will consist of the following components, from bottom to top:

- 20.75-inch x 13.375-inch, 3,000-psia casing head;
- 13.625-inch fiber optic line port/access;
- 13.625-inch x 9.625-inch, 5,000-psia casing head;
- 11-inch x 7.0625-inch, 5,000-psia tubing head;
- 7.0625-inch 5,000-psia full-open master control gate valve;
- 7.0625-inch 5,000-psia automated tubing flow control valve;
- 7.0625-inch 5,000-psia cross with one (1) 7.0625-inch, 5,000-psia blind flange;
- 7.0625-inch 5,000-psia automated tubing flow control valve; and
- 7.0625-inch x 5.5-inch, 5,000-psia top flange and pressure gauge.

The wellhead and Christmas tree will be composed of materials that are designed to be compatible with the injection fluid. Critical components that come into contact with the CO_2 injection fluid will be made of a corrosion-resistant alloy such as stainless steel. Materials that are not expected to contact the injection fluid, such as the surface casing and shallow portion of the long-string casing, will be manufactured of carbon steel. A preliminary materials specification for the wellhead and Christmas tree assembly is described in **Table 22**, using material classes as defined in API Specification 6A (Specification for Wellhead and Christmas Tree Equipment). A summary of material class definitions is provided in **Table 23**. The final wellhead and Christmas tree materials specification may vary slightly from the information given at selection and will meet or exceed what is outlined below. An illustration of the wellhead and Christmas tree is provided in **Figure 42.** The flow line leading to the wellhead and Christmas tree will be equipped with an automatic shutoff valve as required in 40 CFR 146.88(e). Each annulus will be installed with pressure monitoring by pressure gauges installed on the wellhead corresponding to each annulus, as required by 16 TAC 5.203(e)(1)(c)(ii).

Table 22: Materials specification of wellhead and Christmas tree.

Component		Material Class[(a)]
Casing Head Housing (for 20-in. surface casing)		DD, EE
Casing Head Spool (for 13-3/8-in. intermediate casing	Casing spool (20-3/4 in. 3K X 13-5/8 5K)	AA, BB, DD, EE
	Casing hanger (20 in. X 13-3/8 in.)	AA, DD
Tubing Spool Assembly (for 9-5/8-in. long-string casing)	Spool	AA
	Casing hanger	AA, DD
Christmas Tree	Tubing head adapter	DD, EE
	Manual gate valve	BB
	Pneumatic actuated gate valves (2)	BB
	Tubing hanger (for 5.5-in. tubing)	CC

(a) When multiple classes are given, the highest class applies. Vault uses this convention because not all components are available in all class types.

Table 23: Material classes from API 6A (specification for wellhead and Christmas tree equipment).

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
AA – General Service	Carbon or alloy steel	Carbon or low-alloy steel
BB – General Service	Carbon or low-alloy steel	Stainless steel

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
CC – General Service	Stainless steel	Stainless steel
DD – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Carbon or low-alloy steel[(b)]
EE – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Stainless steel[(b)]
FF – Sour Service[(a)]	Stainless steel[(b)]	Stainless steel[(b)]
HH – Sour Service[(a)]	Corrosion-resistant alloy[(b)]	Corrosion-resistant alloy[(b)]

Source: Cameron Surface Systems, Houston, Texas
(a) As defined by National Association of Corrosion Engineers (NACE) Standard MR075.
(b) In compliance with NACE Standard MR0175.

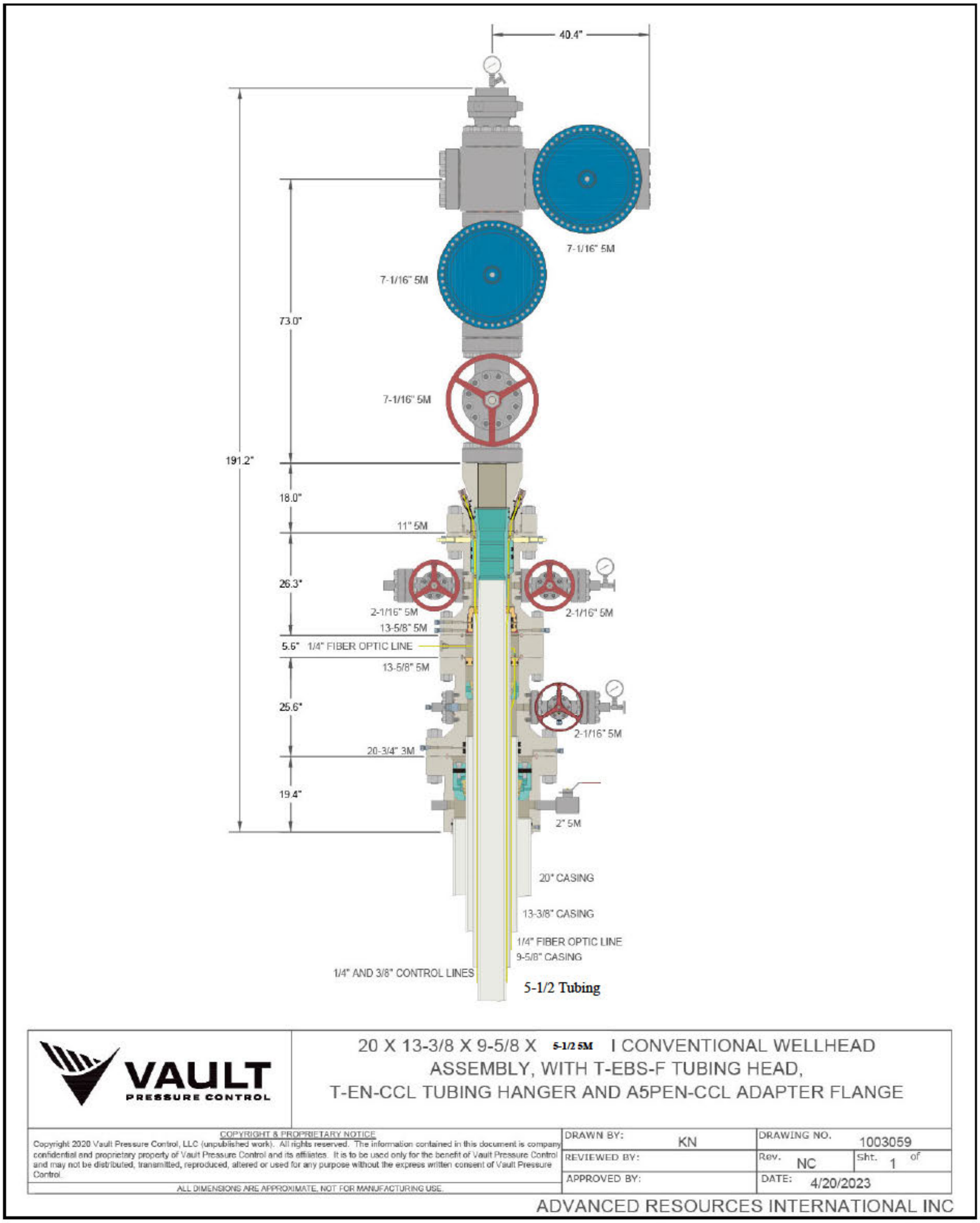

Figure 42: Illustration of the wellhead and Christmas tree.

C.6.3 Perforations

The long-string casing will be perforated across the Frio Formation with deep-penetrating shaped charges. Due to the installation of fiber optics, oriented perforations will be used to avoid damaging the fiber optic cable. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. The planned perforation intervals will be set between 5,953 feet and 6,815 feet with 6 shots-per-foot and oriented to avoid the fiber optics. Proposed perforation interval depths for PW-2 are found below in **Table 24**.

Table 24: Planned perforated intervals (PW-2), subject to change based on injection well characterization data.

Perforated Zones	Perforated Interval No.	Top (ft)	Bottom (ft)	Mid-Point (ft)
Upper Injection Zone (Middle Frio)	1	5,953	6,186	6,384
Lower Injection Zone (Lower Frio)	2	6,384	6,599	6,815

C.6.4 Schematic of the Subsurface Construction Details of the Well

A schematic of the injection well design without sliding sleeves (PW-1 and PW-3) is shown in **Figure 42 43**. A schematic of the injection well design with sliding sleeves (PW-2 and PW-4) is shown in **Figure 44. Figure 45** shows the detail of the perforations, sliding sleeves, gauges, and tubing string packers.

As discussed in the previous sections, the injection well(s) will include the following casing strings: a 20-inch diameter conductor string set at a depth of approximately 60 feet BGS; a 13.325-inch diameter surface string set at a depth of approximately 2,500 feet BGS; and a 9.625-inch diameter deep string set at an approximate depth of 7,300 feet BGS. All depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the CO_2 injection wells. At minimum, the conductor, surface, and long casing strings will be cemented to surface.

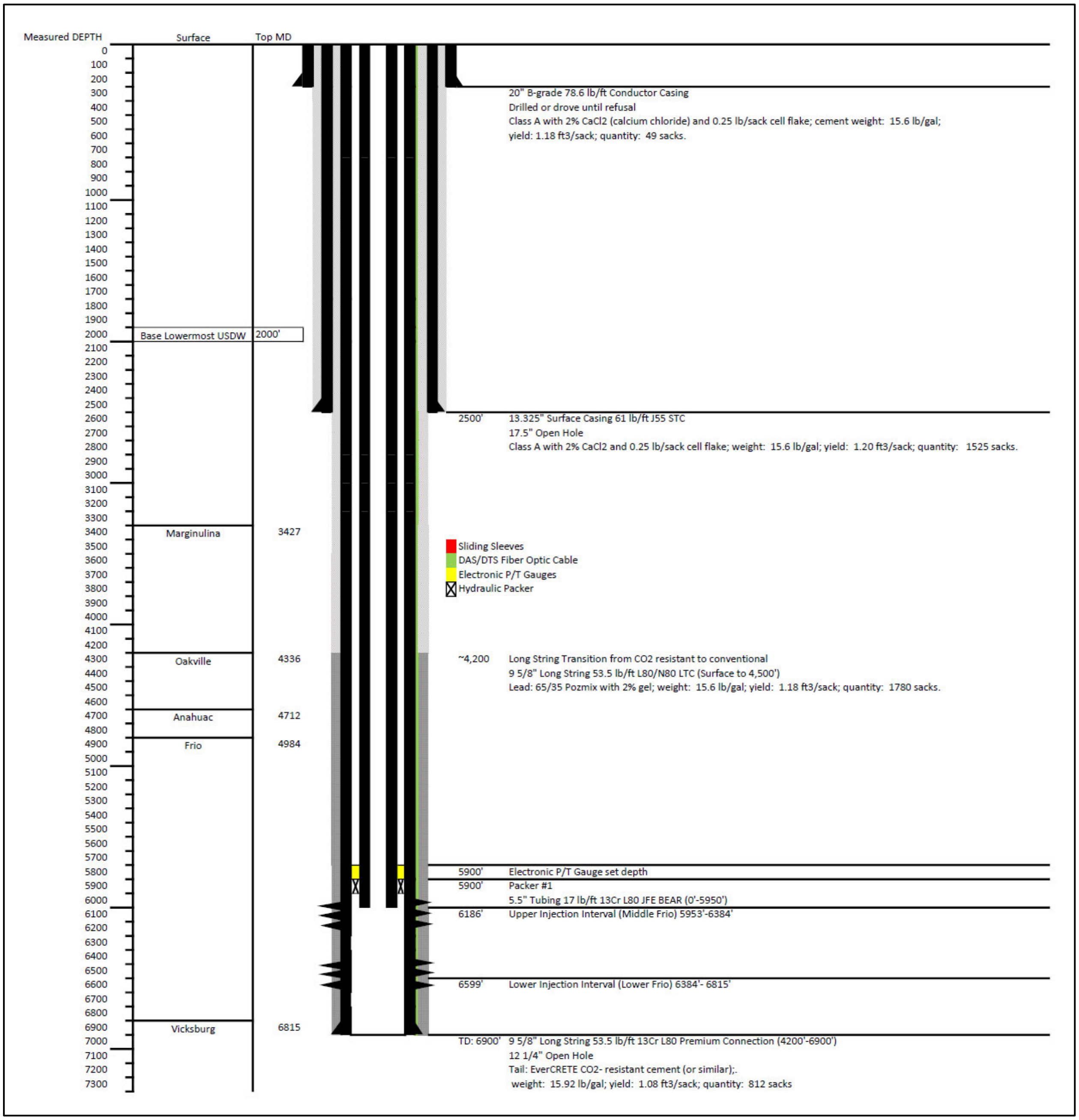

Figure 43: Injection well schematic without sliding sleeves (PW-1 and PW-3).

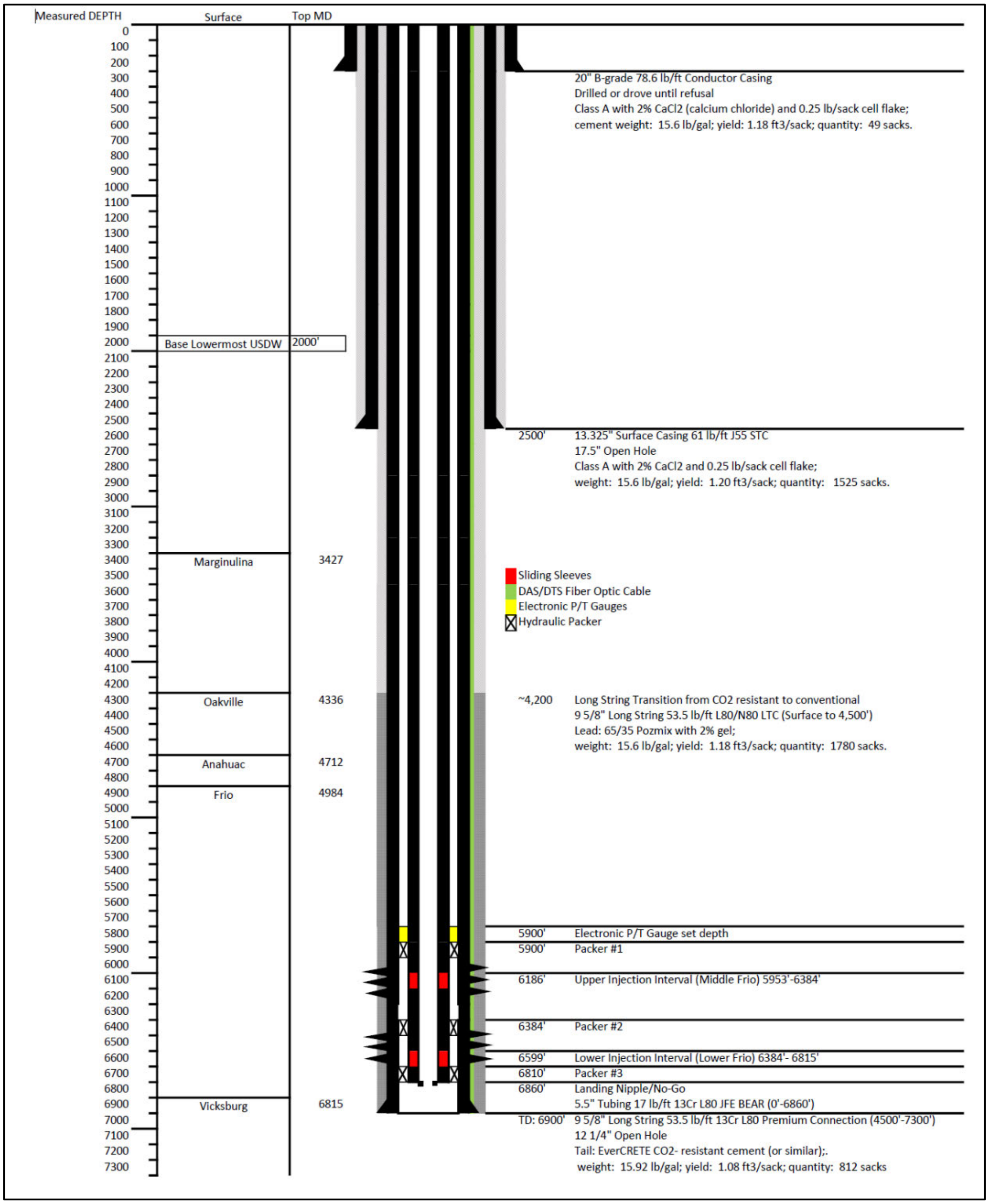

Figure 44: Injection well schematic with sliding sleeves (PW-2 and PW-4).

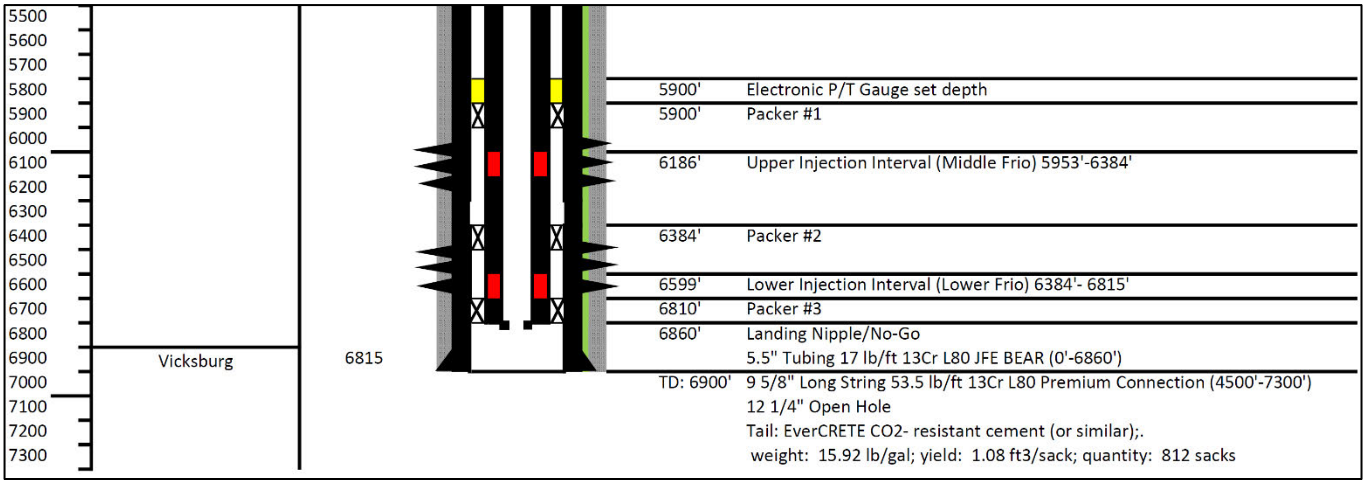

Figure 45: Injection well schematic with sliding sleeves (Zoomed 5,500-7,300 ft).

D. INJECTION WELL OPERATIONS PLAN

D.1 Introduction

By following the injection well operations program for the Pineywoods CCS Hub described in this Plan, Pineywoods CCS, LLC seeks to safely inject an average rate of 1.25 MMt/y per well (64.7 MMcf/day) of CO_2 into the Frio reservoir at four injection wells, PW-1, PW-2, PW-3, and PW-4 while avoiding geomechanical effects and maintaining well integrity. At full operations, the four injection wells will be injecting up to 5 MMt/y (258.9 MMcf/day) total into the lower Frio Formation (see **Figure 2** for well locations). The operational details provided in this document satisfy 40 CFR 146.82(a)(7) and (10) and 16 TAC 5.203(i). The operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88 and 16 TAC 5.208(d)(2).

D.2 Specifications of the CO_2 Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The CO_2 will be sourced from a series of industrial and power plants located in the Houston and Beaumont areas and transported by pipeline to the Pineywoods CCS Hub. The CO_2 will enter a distribution header near PW-2 and be piped to each injection wellhead. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore. The injectate stream composition coming into the storage field will vary throughout the injection phase of the project. To account for this, Pineywoods CCS, LLC plans to continuously monitor the CO_2 stream chemical composition to ensure it meets minimum composition specifications that will be refined when sources are finalized and capture equipment is operational (see **Section B of the Testing and Monitoring Plan**). The CO_2 injection stream coming into the storage site is expected to have at least the specifications presented in **Table 25**.

Table 25: Specifications of the anticipated CO_2 stream composition.

Component	Specification	Unit
Minimum CO_2	>96	mole%, dry basis
Water content	<20	lb/MMscf
Impurities (dry basis):		
Total Hydrocarbons	<2	mol%
Inert Gases (N_2, Ar, O_2)	<4	mol%
Hydrogen	<1	mol%
Alcohols, aldehydes, esters	<500	ppmv
Hydrogen Sulfide	<50	ppmv
Total Sulfur	<100	ppmv
Oxygen	<100	ppmv
Carbon monoxide	<100	ppmv
Glycol	<1	ppmv

On average, the CO_2 stream will be 75 ºF and approximately 1,500 psi in the pipeline, with an estimated density of 48.3 lb/ft^3 at wellhead conditions. After injection into the Frio Formation, the CO_2 stream is anticipated to heat to near formation temperature of approximately 151 ºF at or above the native reservoir pressure of approximately 2,850 psi, with an estimated density of 50.4 lb/ft^3, in a supercritical state (NIST).

Due to the anticipated low water content within the CO_2 stream, CO_2-induced corrosion affecting well components is not likely - as noted by the U.S. EPA well construction guidance (EPA, 2012). Pineywoods CCS, LLC will, however, monitor for potential corrosion induced by the injectate as outlined in **Section D of the Testing and Monitoring Plan**.

D.3 Operational Procedures [40 CFR 146.82(a)(10)]

The operational procedures described here were developed to factor in the thermohydraulic performance of the four injection wells based on wellbore design parameters described in **Section C of this Application Narrative**. The analysis of the design parameters and ensuing calculations are also described in **Section C of this Application Narrative**.

D.3.1 Operational Conditions

Pineywoods CCS, LLC plans to inject 1.25 MMt/y (3,425 t/d) of CO_2 at each of four injection wells. As described in **Section C.3 of this Application Narrative**, PW-2 and PW-4 will be equipped with a series of sliding sleeves across the formation to prevent the injection stream from flashing in a low injection volume scenario. To confirm that this annual injection rate of 1.25 MMt/y can be achieved with the proposed well design, as well as the proposed maximum instantaneous injection rate of 1.50 MMt/y (4,111 t/d), operational conditions for both well construction types and both injection rates were modeled using SLB *PIPESIM* software, a steady-state multi-phase flow simulator.

Calculations in *PIPESIM* consider the pressure-volume-temperature (PVT) properties of CO_2 flowing through a 5.5-inch tubing with sliding sleeves to a bottomhole depth of 6,100 ft. Pressure along the wellbore tubulars was modeled using surface roughness (friction), hydrostatic effects, and fluid velocity. **Table 26** summarizes the operational inputs for the SLB *PIPESIM* analysis. The injection wells will be continually monitored for injection pressure, rate, volume, temperature of the CO_2 stream, and tubing-long string casing annulus pressure and fluid volume. The continuous monitoring program for pressure and injection rates is included in **Section C of the Testing and Monitoring Plan**. Injection will occur through the injection tubing string and never between the outermost casing protecting USDWs and the tubing (40 CFR 146.88(b); 16 TAC 206(d)(2)(A)).

Table 26: Inputs to wellbore calculations in SLB *PIPESIM*.

Input Parameter	Value	Unit
Injection Zone Permeability	219	mD
Wellhead Temperature	75	°F
Injection Zone Temperature	155	°F
Damaged Permeability Ratio	0.1	n/a
Skin Permeability Ratio	0.3	n/a
Upper Injection Zone Top Depth	6,106	ft
Upper Injection Zone Bottom Depth	6,667	ft
Lower Injection Zone Top Depth	6,667	ft
Lower Injection Zone Bottom Depth	7,228	ft
CO_2 Purity	99.5	%
Perforations (60-degree phase)	6	Shots per Foot
Pressure Gradient	0.465	psi per ft
Temperature Gradient	1.32	°F per 100 ft

PIPESIM analysis of an injection rate of 1.25 MMt/y in a well that has been constructed without sliding sleeves (equivalent to two fully open sliding sleeves) resulted in a wellhead pressure of 1,114 psia, shown in **Figure 35**. At the maximum instantaneous injection rate of 1.50 MMt/y, the resulting wellhead pressure is expected to be 1,171 psia, shown in **Figure 36**.

Multiple scenarios with the sliding sleeves were modeled, an injection rate of 1.25 MMt/y and the lower perforations closed and upper perforations open. The *PIPESIM* analysis resulted in a wellhead pressure of 1,152 psia, shown in **Figure 37.** Additional SLB *PIPESIM* nodal analysis inputs and results can be found in **Section D.5. and C.1 of this Application Narrative**.

The estimated hydraulic fracture gradient and the hydraulic fracture pressure at the injection zone top-depth in the *PIPESIM* model is 4,274 psi (0.7 psi/ft * 6,106 ft), corresponding to a maximum bottomhole pressure of 3,846 psi, as required by 40 CFR 146.88(a) to not exceed 90% of the fracture pressure of the injection zone. See **Table 28** for well specific bottomhole injection pressure limits. The modeled bottomhole pressure and the increased reservoir pressure during injection (See **Section A.3.d of the Area of Review and Corrective Action Plan**) for all injection rates was considerably less than 90% of the fracture pressure of the reservoir.

Injection tubing will be deployed and set via a packer placed above the perforations. The injection wells will be monitored for potential annular leaks and external mechanical integrity as outlined in **Section F of the Testing and Monitoring Plan**. The annular space between the long-string casing and the injection tubing will be filled with a corrosion inhibitor as described in **Section C.5.1 of this Application Narrative**.

The annular pressure between the tubing and the casing downhole will be maintained at a pressure higher than the injection pressure during injection to satisfy requirements in 40 CFR 146.88(c). Annular pressure may be reduced during periods of well workover (maintenance) approved by the UIC Program Director in which the sealed tubing/casing annulus is disassembled for maintenance or corrective procedures.

D.3.2 Injection Start-Up

Pineywoods CCS, LLC will ramp up injection operations as detailed in **Table 27** and conduct operational monitoring of the injection site pursuant to 40 CFR 146.90(b). Specific details of the startup protocol are outlined below.

A multi-stage startup procedure will be implemented in conjunction with data acquired from surface and downhole pressure and temperature gauges in all injection wells, as well as in-zone and above-zone observation wells.

During the start-up period, Pineywoods CCS, LLC will collect daily operational data and include these data in semi-annual reports as required by 40 CFR 146.91(a) and described in **Section A.6 of the Testing and Monitoring Plan**. At the UIC Program Director's request, Pineywoods CCS, LLC will schedule a conference call to discuss the operational data during the start-up.

A series of successively higher injection rates will be used during injection start-up (an example start-up operational procedure is shown in **Table 27** and may be modified to accommodate the available volume of CO_2 at the start of injection), with the elapsed time and pressure values recorded for each rate and time step. Each rate step will last approximately 24 hours. At no point during the procedure will the injection pressure exceed the maximum permitted bottomhole injection pressure which is 90% of the top Frio Formation injection interval depth fracture pressure (see **Section D.3.1** above). If requested by the UIC Program Director, Pineywoods CCS, LLC will provide the final start-up operational procedure.

Table 27: Example operational procedure during start-up.

Rate (t/d)	Duration (Hours)	Percent of Maximum Injection Rate (%)
572	24	16.7
1,142	24	33.3
1,712	24	50.0
2,284	24	66.7
2,853	24	83.3

Injection rates will be measured (using a Coriolis flow meter), and data will be continuously recorded. Surface and downhole pressure and temperature data will be collected continuously in the injection and observation wells. During the start-up period, a plot of injection rate and the corresponding stabilized pressure values will be graphically represented to demonstrate that well integrity has been maintained.

During the start-up period, the project team will look for any evidence of anomalous pressure behavior. If anomalous pressure behavior is observed, the project team will conduct additional monitoring to better characterize the anomaly. If during the start-up period the project team determines that anomalous pressure behavior indicates a downhole pressure that could lead to formation fracturing, injection will be stopped, and the line valve closed allowing the pressure to bleed-off into the injection zone. The instantaneous shut-in pressure (ISIP) will be measured, and the pressure data will be reviewed for event signatures. In this event, Pineywoods CCS, LLC will notify the UIC Program Director within 24 hours of the root cause determination. Pineywoods CCS, LLC will consult with the UIC Program Director before initiating further injection.

D.4 Injection Rates

The injection wells will be constructed as shown in **Section C of this Project Narrative**. Injection will be facilitated through injection tubing set in the long casing string, with sliding sleeves at each injection interval for PW-2 and PW-4 only, and by a packer above the topmost perforations in the Frio Formation.

Table 28 summarizes the proposed operational parameters for all injection wells. Operational parameters are expected to remain constant throughout the duration of the injection period. Some variability to operational parameters may stem from variations in volume from a CO_2 source, which may lead to lower injection volumes during limited periods of time. The injection rate values detailed in **Table 28** were modeled in *PIPESIM*, and the nodal analysis results can be found in **Section C.1 of this Application Narrative**.

Table 28: Injection well operational parameters.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
At Wellhead (All Injection Wells)	1,500	psia
Downhole – PW-1	3,846	psia
Downhole – PW-2	3,750	psia
Downhole – PW-3	3,562	psia
Downhole – PW-4	3,409	psia
Injection Rates		
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	4,110	t/d
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	1.5	MMt/y
Average Injection Rate (CO_2) (One Injection Well)	3,425	t/d
Average Injection Rate (CO_2) (One Injection Well)	1.25	MMt/y
Maximum Annual Injection (CO_2) (One Injection Well)	1.25	MMt
Maximum Annual Injection (CO_2) (Four Injection Wells)	5	MMt
Total Injection Mass (30-year period) (One Injection Well)	37.5	MMt
Total Injection Mass (30-year period) (Four Injection Wells)	150	MMt
Annular Pressure		
Maximum Annulus Surface Pressure (All Injection Wells)	500	psia
Minimum Annulus Pressure at the Wellhead (All Injection Wells)	250	psia

Using a per well average annual CO_2 injection rate of 1.25 MMt/y (3,425 t/d) and a maximum instantaneous rate of 1.5 MMt/y (4,110 t/d), the injection tubing string size was selected to meet project requirements. The expected wellhead pressure during injection operations will likely be between 1,100 psia and 1,200 psia but may be as high as 1,300 psia during maximum instantaneous injection periods. At a wellhead pressure of 1,226 psia and a maximum instantaneous rate of 4,110 t/d, bottomhole pressures are still considerably less than the maximum allowable downhole pressure for all injection wells.

Based on expected operating ranges, Pineywoods CCS, LLC proposes to maintain annular pressure at the surface between 250 to 500 psia. Because of the lower CO_2 density in the injection tubing string, this should result in bottomhole conditions whereby the annular fluid is at a higher pressure than that within the injection tubing string. Final design criteria will be developed for the permission to operate the injection well.

D.5 Estimated Maximum Allowable Surface Pressure

In *PIPESIM,* the maximum allowable wellhead pressure observed during simulation of injection in a well with sliding sleeves and a bottomhole pressure of 3,750 psia (90% fracture pressure at a depth of 5,953 ft) was 1,781 psia, shown in **Figure 46**. When injection was modeled using a maximum instantaneous rate of 1.5 MMt/y (4,110 t/d), the resulting wellhead pressure was 1,171 psia. The maximum allowable surface pressure (MASP) for all injection wells will be 1,500 psia, well below the modeled maximum allowable wellhead pressure of 1,781 psia that corresponds with bottomhole pressures near 90% of fracture pressure. Operating wellhead pressures will likely range from 1,100 to 1,200 psia.

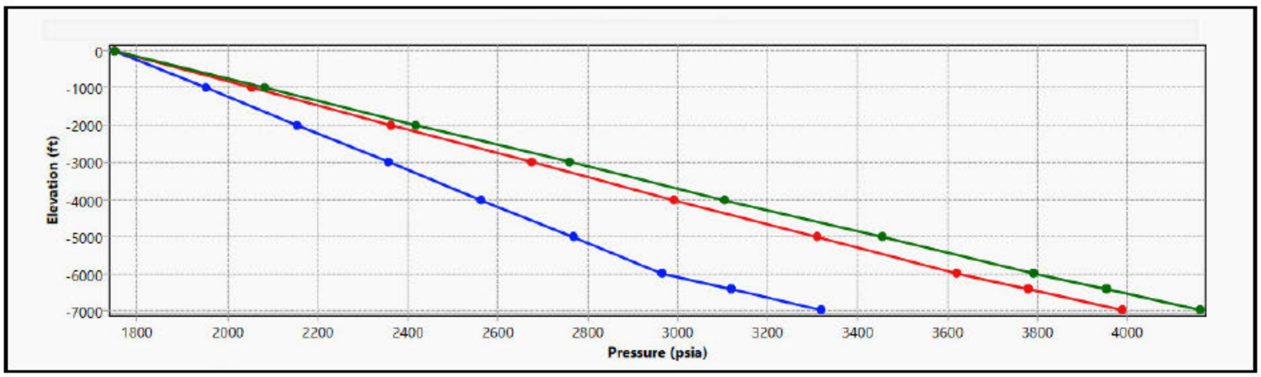

Figure 46: Pressure Versus Depth Profile at 90% of Fracture Pressure at the Top of the Frio Formation (PW-2 and PW-4).

D.6 Injection Well Operational Monitoring

Each injection well will be monitored to ensure safe operations, in compliance with 40 CFR 146.88(e)(2) and 16 TAC 5.206(d)(2). Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and bottomhole, continuous monitoring of the pressurized annulus, continuous fiber optic temperature monitoring along the well, and corrosion coupon monitoring to identify corrosion. Each of these monitoring systems is fully described in **Sections C and D of the Testing and Monitoring Plan**.

Each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the well if: (1) the MASP is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the annulus fluid pressure drops below the injection pressure. Injection parameters, including pressure, rate, volume and/or mass, and temperature of the CO_2 stream, will be continuously measured and recorded. The pressure and fluid volume of the annulus between the tubing and long-string casing will also be continuously recorded.

All automatic shutdowns will be investigated prior to bringing injection back online to ensure that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Pineywoods CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Please refer to **Appendix A of the Emergency and Remedial Response Plan** for response actions if mechanical integrity is lost.

The annular space between the tubing and long string casing of each injection well will be pressurized with corrosion inhibiting brine and monitored for changes in pressure and volume. The fiber optic cable cemented onto the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing through the primary confining unit, the Anahuac. Rapid temperature changes or other excursions from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

D.7 Workover and Maintenance

Pineywoods CCS, LLC will monitor and maintain mechanical integrity of each injection well at all times. Well maintenance and workovers will be part of normal operations to keep each injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is not a loss of mechanical integrity. Barriers, such as a downhole plug, will be placed to ensure leakage risk is minimized. As outlined in **Section A.6 of the Testing and Monitoring Plan**, Pineywoods CCS, LLC will notify the UIC Program Director of any planned workover or injection well test at least 30 days in advance, and the results of any mechanical integrity test, workover, or injection well test will be provided within 30 days after the test or maintenance is completed (40 CFR 146.91).

Each injection well is designed to allow the installation of a temporary plug below the tubing to allow the tubing to be removed and replaced as needed while keeping a barrier in place. The bottomhole temperature and pressure gauge is set above the packer to allow for replacement, if needed, without removing the packer from the well.

E. SUMMARY OF OTHER PLANS

E.1 Area of Review and Corrective Action Plan

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)]***

The information and files submitted in the **Area of Review and Corrective Action Plan** satisfy the federal requirements of 40 CFR 146.84 and state requirements of 16 TAC 5.203(d). This plan addresses how the Area of Review (AOR) is delineated and uses corrective action techniques to address all deficient artificial penetrations and other features that compromise the integrity of the confining zone above the injection zone. The AOR encompasses the entire region surrounding the injection wells at the Pineywoods CCS Hub where USDWs may be endangered by injection activity. The AOR is delineated by the maximum extent of the pressure front or CO_2 plume over the lifetime of the project. The **Computational Model** describes modeling of the subsurface injection of CO_2 into the Lower Frio Formation at the Pineywoods CCS Hub. The *GEM* simulator was used to assess the development of the CO_2 plume, the pressure front, and the long-term fate of the injected CO_2. Simulation indicated that the maximum extent of the pressure front will be larger than the maximum extent of the CO_2 plume over the lifetime of the project. Therefore, the AOR for the Pineywoods CCS Hub is defined as the maximum extent of the threshold pressure front, which is at the end of injection. This plan details the computational modeling, assumptions that were made, and site characterization data that the model was based on to satisfy the requirements of 40 CFR 146.84(c)**.**

There are 169 existing oil and gas wellbores and 116 water wells within the AOR. Per 40 CFR 146.82(a)(4), wells that penetrate the injection or confining zone within the AOR must be tabulated. None of the water wells penetrate the injection or confining zones, but there are up to 153 oil and gas wellbores that may penetrate the primary confining unit within the AOR, as listed in **Appendix A and Appendix C of the Area of Review and Corrective Action Plan**. Well records are included in **Appendix B of the Area of Review and Corrective Action Plan.** Pineywoods CCS, LLC proposes a sequential corrective action strategy based on temporal evolution of the threshold pressure boundary, beginning prior to injection and ending in the 18th year of injection.

Pineywoods CCS, LLC will review the AOR annually during the injection phase and once every two years during the post-injection phase to ensure the initial model predictions are adequate for predicting the extent of the CO_2 plume and pressure front.

E.2 Financial Responsibility

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]***

Pineywoods CCS, LLC has prepared the **Financial Responsibility Demonstration** to comply with federal requirements at 40 CFR 146.85 and state requirements at 16 TAC 5.203(n) and 5.205. The plan estimates costs of project activities and provides information on financial instruments that Pineywoods CCS, LLC proposes to use to demonstrate Financial Responsibility for the following activities: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care; (4) Site Closure; and (5) Emergency and Remedial Response. The **Financial Responsibility Demonstration** includes financial instruments to cover the costs of one emergency leakage event as discussed in the **ERRP**, all of the costs of injection well plugging as discussed in the **Injection Well Plugging Plan**, all of the costs of corrective action as discussed in the **Area of Review and Corrective Action Plan**, all of the costs of 50 years of post-injection site care as discussed in the **Post-Injection Site Care and Site Closure Plan**, and all of the costs of plugging observation wells and restoring the site as discussed in the **Injection Well Plugging Plan** and **Post-Injection Site Care and Site Closure Plan**.

E.3 Pre-Operational Testing Plan

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]***

The **Pre-Operational Testing Plan** is designed to establish an accurate baseline dataset of pre-injection site conditions, verify depths and physical characteristics of geologic formations germane to the injection and confining zones, and ensure that injection well construction satisfies requirements outlined in 40 CFR 146.86. This plan meets the federal requirements at 40 CFR 146.87 and state requirements at 16 TAC 5.203(f).

During the drilling and construction phase of the project, appropriate log suites, surveys, and tests will be deployed to verify the depth, thickness, porosity, permeability, and lithology of pertinent geologic formations, as well as the salinity of formation fluids within them. Deviation checks will be performed during drilling at frequent intervals to keep track of the borehole location in the subsurface and serve as a reference for steering purposes to achieve as near to vertical wellbore as possible. These checks will also assist in assuring that avenues for vertical fluid movement are not created in the form of diverging holes while drilling. Mudlogs will be acquired throughout the drilling process. When the well reaches 2,200 ft., resistivity, spontaneous potential, and caliper logs will be run before surface casing is run. A cement bond log will be run to evaluate radial cement quality once the casing is cemented in place.

Once the well is drilled to total depth (TD), resistivity and spontaneous potential logs, porosity, caliper, gamma ray, NMR, sonic, and formation micro imager logs will be run prior to the installation of the long string casing. Cement bond, variable density, and temperature logs will be run after long string casing is cemented in place to verify the quality of the cement job. Internal and external mechanical integrity of the injection wells will be tested to demonstrate the absence of leaks in the wellbore that could result in migration of CO_2 out of the injection zone. An annular pressure test will be performed within 24 hours of cementing casing.

Sidewall core samples will be taken from the confining and injection zones while drilling the first injection well, PW-2. Analysis of these samples will be correlated to analysis of well logs as part of the pre-operational geologic site characterization updates. Fluid samples will be collected from the injection zone in the proposed injection wells to establish baseline measurements for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. Fracture pressure will be determined using the formation testing tool and minifrac tests in the observation well. Fracture pressure tests will not be conducted in the injection wells to prevent borehole rugosity and washouts and ensure mechanically sound cement jobs.

Upon completion and before operation, hydrogeologic characteristics of the injection zone will be determined by performing a composite injectivity evaluation test in the injection interval to determine the large-scale transmissivity through the reservoir. Reports detailing the results and interpretations of all testing operations will be provided to the UIC Program Director following conclusion of analysis.

E.4 Testing and Monitoring Plan

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]***

This plan is designed to ensure that injection and storage of CO_2 at the Pineywoods CCS Hub is done safely, without endangerment to local USDWs or communities, and satisfies the federal requirements under 40 CFR 146.90 and state requirements under 16 TAC 5.203(j). A **Quality Assurance and Surveillance Plan** is provided as Appendix A to this plan.

Pineywoods CCS, LLC plans to drill up to 24 wells strategically placed in specific formations (Figure 1) to ensure the protection of groundwater resources. These wells include four injection wells completed in the Lower Frio Formation, four in-zone observation wells completed in the Lower Frio Formation, three above-zone observation wells completed in the Lower Miocene 1 Formation, six deep observation wells completed in the lowermost USDW of the Upper Miocene Evangeline Aquifer, and up to seven shallow USDW wells completed in the Pliocene Chicot Freshwater Aquifer.

Data collected during the implementation of this plan will be used to confirm that injection procedures are operating as planned, that USDWs are protected, and that the CO_2 plume and pressure front are developing as predicted. The monitoring data will also be used to validate and update geologic and reservoir simulation models. These models, being the primary method of forecasting the position, pressure, and saturation of the injected CO_2 within the Pineywoods CCS Hub, will ultimately support and demonstrate the safe and permanent storage of CO_2 throughout the project. **Table 29** summarizes the well-based testing and monitoring activities that are proposed for the Pineywoods CCS Hub.

Pineywoods CCS, LLC expects multiple sources of CO_2, with additional sources to be added throughout the life of the project. As such, Pineywoods CCS, LLC will continuously monitor the CO_2 stream with a gas chromatograph to ensure the physical and chemical characteristics of the CO_2 stream are as anticipated. Corrosion monitoring will occur quarterly by analyzing coupons of materials used to construct the CO_2 flowlines, long string casing, injecting tubing, wellhead, and packer that are exposed to the CO_2 stream while injection is occurring.

Table 29: Summary of Testing and Monitoring Activities to be Conducted at the Pineywoods CCS Hub

Monitoring Category	**Monitoring Parameter/Method**		**Baseline Frequency (1 year)**	**Injection Phase Frequency (30 years)**	**Post-Injection Frequency (20 years)**
Monitoring Plan Update	Review Every 5 Years *Updated as Required*		N/A	Update As Required	Update As Required
CO_2 Injection Stream Analysis	Chemical Characteristics		N/A	Continuous	N/A
	Physical Characteristics		N/A	Continuous	N/A
CO_2 Injection Process Monitoring	Injection Rate		N/A	Continuous	N/A
	Injection Physical Characteristics		N/A	Continuous	N/A
	Annulus Pressure Monitoring		N/A	Continuous	N/A
	Annulus Volume Added		N/A	Continuous	N/A
Hydrogeologic Testing	Pressure Fall-Off Testing		1 Prior to Injection	3 Years After Injection, 1 Every 5 years After	N/A
Injection Well Mechanical Integrity Testing	Internal *Annulus*	Pressure Test	1 Prior to Injection	N/A	*N/A*
		Pressure Monitoring	N/A	Continuous	Continuous
	External *Temp.*	1) DTS *AND/OR* 2) Temp. Log 3) PNC Logging 4) Ultra Sonic CBL 5) Electromag. CI Logs	1 MIT Prior to Injection: 1 *OR* 2 *AND* 3-5	1 MIT Annually *OR one of:* 2-5) Annually	N/A
Corrosion Monitoring	Corrosion Coupon Testing		N/A	Quarterly	N/A
Groundwater Quality and Geochemistry Monitoring	*Fluid Sampling and Analysis*	*Lowermost USDW*	Quarterly – 1 Year Prior to Injection	Quarterly for 1st Year, Annually Thereafter.	Annually
		Above-Zone			
		In-Zone			N/A
Direct Pressure Plume Monitoring	Wellhead P Gauges Downhole P Gauges		Continuous, After Well Construction	Continuous	Continuous
Indirect Plume Monitoring Techniques	*Fiber & Wireline*	DTS	Prior to Injection	Continuous	Continuous
		PNC Logging	1 Prior to Injection	3 Years After Injection, 1 Every 5 Years After	1 Every 5 Years
	Repeat Seismic	3D DAS VSP *OR* Seismic	1 Prior to Injection	3 Years After Injection, 1 Every 5 Years After	1 Every 5 Years

Pineywoods CCS, LLC will use continuous recording devices to monitor the injection pressure, rate, and volume; the pressure of the annulus between the long string casing; and the annulus fluid volume added. The downhole annulus pressure will be maintained at a pressure greater than the operating injection pressure during periods of injection. Fiber optic cable will be installed on the outside of the long string casing for all injection and in-zone monitoring wells and will allow for continuous geophysical monitoring through distributed acoustic sensing (DAS) and provide insight into the vertical plume imaging and external mechanical integrity through distributed temperature sensing (DTS).

Pineywoods CCS, LLC will conduct Mechanical Integrity Testing (MITs) on all injection and in-zone observation wells prior to injection and during injection operations. Internal mechanical integrity will be demonstrated prior to injection through an annulus pressure test per 40 CFR 146.87(a). During injection, all injection wells will be continuously monitored for internal mechanical integrity by implementing continuous annular pressure monitoring per 40 CFR 146.89(b). External mechanical integrity will be monitored using continuous temperature profiling through installation of DTS fiber-optic cable along the long string casing in the injection wells. These data will replace the need for a temperature log to demonstrate external mechanical integrity. External MITs will be run prior to injection per 40 CFR 146.87(a)(4), annually during injection per 40 CFR 146.89(c) and 40 CFR 146.90(e), and prior to injection well plugging after cessation of injection per 40 CFR 146.92(a). Pulsar logging will occur in all injection, in-zone, above-zone, and deep wells prior to injection to baseline pre-injection reservoir and aquifer conditions. During injection, PNC logs will be run in injections wells 3 years after injection begins and every 5 years thereafter. Pulsar logging will occur in wells with detected CO_2 breakthrough and containment loss to aid reservoir models in CO_2 plume prediction and verify containment and that the CO_2 plume is behaving as predicted.

Pineywoods CCS, LLC will monitor groundwater quality and geochemistry analyses during the injection phase of the project per 40 CFR 146.90(d) and 16 TAC 203.5(j)(2)(D). Pineywoods CCS, LLC. will conduct baseline groundwater geochemistry monitoring prior to injection in all injection, in-zone, above-zone, and deep observation wells on a quarterly basis one year prior to injection. Baseline groundwater quality (i.e., pressure) will be conducted after completion of the well and prior to injection. During injection, groundwater geochemistry will be conducted quarterly for the first year and then annually thereafter. Groundwater quality will be conducted continuously during injection. Groundwater geochemistry will be conducted through fluid sampling and laboratory analyses looking for specific analytes described in **Table 9 of the Testing and Monitoring Plan**. Groundwater quality (i.e., pressure) data will be collected using downhole permanent pressure sensors and transducers set above and ported down through the packers to each injection and observation well's respective monitoring zone (see **Table 27** above). Injection phase data will be compared to baseline data to detect and verify containment loss. Above-zone and deep observation well groundwater quality and geochemistry data will be used to provide evidence for the demonstration of protection of groundwater resources and ultimately site closure.

Pineywoods CCS, LLC will utilize direct and indirect methods to track the extent of the pressure and CO_2 plume throughout the life of the project. Continuous direct downhole pressure and temperature monitoring will be performed in all injection wells, in-zone, above-zone, and deep observation wells with real-time surface read-out capabilities per 40 CFR 146.90(g)(1). Indirect CO_2 plume monitoring will occur through 3D plume imaging using 3D DAS VSPs, CO_2 saturation profiling using Pulsar logging, and DTS along with wellbore temperature profiling to collectively monitor the plume in three dimensions per 40 CFR 146.90(g)(2). These monitoring data will allow Pineywoods CCS, LLC to ensure the injection zone pressure front and CO_2 plume are behaving as expected and validate or update computational models using real pressure and saturation data per 40 CFR 146.84.

E.5 Injection Well Plugging

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)]***

The Injection Well Plugging Plan is designed to comply with federal requirements at 40 CFR 146.92 and 146.93(e) and state requirements at 16 TAC 3.14, 5.203(k), and 76, which include addressing the plan to plug both injection wells and observation wells at the Pineywoods CCS Hub. For five years after the 30-year injection period, the injection wells will be used as observation wells to ensure containment of the CO_2 in the injection zone, after which they will be plugged. Prior to plugging, the final bottom-hole pressure of the injection wells will be measured, and a buffered fluid (brine) will be used to flush and fill the wells to maintain pressure control. The injection tubing strings, packers, and gauges will be removed from the wells. The mechanical integrity of the wells will be determined to ensure no communication has been established between the injection zone and the USDWs or ground surface (per 40 CFR 146.92). Finally, the entire wellbore will be filled with cement, from the total depth to surface. CO_2 resistant cement will be squeezed into the perforations to seal and fill the wellbore to 500 feet above the caprock. The remaining wellbore will be filled with standard cement to surface. The casing will then be cut at least 3 feet below ground level and sealed with a welded steel plate. Federal and state plugging notifications and reports will be submitted as detailed in the plan.

E.6 Post-Injection Site Care (PISC) and Site Closure

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)]***

The Post-Injection Site Care (PISC) timeframe will begin when all CO_2 injection ceases and ends with site closure. Pineywoods CCS, LLC provides a plan demonstrating a 50-year PISC timeframe but proposes a 20-year PISC timeframe based on results from computational modeling as discussed in the **Area of Review and Corrective Action Plan**. Per 40 CFR 146.93(b)**,** Pineywoods CCS, LLC will monitor the project site for CO_2 plume movement and pressure fall-off to demonstrate non-endangerment of USDWs throughout the PISC timeframe. This plan describes the post-injection modeling that was completed to determine the pressure differential, position of the CO_2 plume, and prediction of CO_2 migration. Pineywoods CCS, LLC also provides information required under 40 CFR 146.93(c) to demonstrate a 20-year PISC timeframe based on available modeling data. Additionally, the plan provides a detailed description of the post-injection monitoring plan and the site-closure activities. The numerical reservoir model used for calculating the AOR was also used for the PISC and site-closure analysis.

The predicted positions of the threshold pressure front and CO_2 plume at the end of 30 years of injection and 50 years post injection were simulated in the model. The simulation indicates that the CO_2 plume becomes nearly stagnant in the 20^{th} year post injection. There are no substantial differences between the CO_2 plume between the 20^{th} and 50^{th} year post injection. The pressure front dissipates completely from the modeled area within 14 years post injection. Based on the modeling results, it is estimated that there is not sufficient hydrostatic pressure in the injection zone to push fluids into or interact with the lowermost USDW or expansion of the CO_2 plume after the 20^{th} year post injection.

Following the cessation of injection, the injection wells will be converted to observation wells for 5 years to capture the pressure drop-off after injection cessation and contribute to the collection of data as part of the monitoring program and demonstration of protection of groundwater resources. The post-injection phase will include monitoring for groundwater quality and geochemistry, direct pressure front tracking, and indirect CO_2 plume imaging. Groundwater geochemistry will be monitored through fluid sampling and analysis. Groundwater quality (i.e., pressure) will be monitored using downhole pressure-temperature gauges. Downhole and surface pressure-temperature gauges will be used to directly monitor and track the pressure front dissipation after injection cessation and update the computational model. 3D DAS VSP repeat seismic surveys, Pulsar CO_2 saturation logging, and DTS temperature profiles will be used to indirectly image the CO_2 plume in three dimensions and update the computational model. Data collected during the post-injection phase will be used as evidence for protection of groundwater resources, pressure front stabilization, and CO_2 plume stabilization in the non-endangerment demonstration required for site closure.

Once Pineywoods CCS, LLC demonstrates plume and pressure stabilization, as well as non-endangerment of local USDWs, well plugging and abandonment of the remaining active injection wells will commence. Abandonment will be performed to preclude the movement of injection or formation fluids out of the storage complex. Prior to well plugging, the mechanical integrity of the wells will be verified by DTS and distributed acoustic sensing (DAS) fiber optic systems emplaced in the observation wells. The well plugging and abandonment will follow the methodology described in the **Injection Well Plugging Plan**.

E.7 Emergency and Remedial Response

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)]***

The **ERRP** details actions that Pineywoods CCS, LLC will take to address movement of the injection fluid or formation fluid in a manner that may endanger a USDW during the construction, operation, or post-injection site care periods, pursuant to federal requirements at 40 CFR 146.82(a)(19) and 146.94(a) and state requirements at 16 TAC 5.203(l). Examples of potential risks include: (1) injection or observation well integrity failure, (2) injection well monitoring and/or surface equipment failure, (3) natural disaster, (4) fluid leakage into a USDW, (5) CO_2 leakage to USDW or land surface, or (6) an induced seismic event. In the case of one of the listed risks, site personnel, project personnel, and local authorities will be relied upon to implement this **ERRP**. Pineywoods CCS, LLC will communicate to the public any major emergency, as described in the **ERRP**, to ensure that the public understands what happened and whether there are any environmental or safety implications. This will include a detailed description of what happened, any impacts to the environment or other local resources, how the event was investigated, what actions were taken, and the status of the remediation.

The emergency contact list in **Appendix B of the ERRP** will be updated annually at a minimum, and the **ERRP** will be reviewed at least once every five years following its approval as well as within one year of an AOR reevaluation and following any significant changes to the injection process or the injection facility or an emergency event. Periodic training will be provided to well operators, plant safety and environmental personnel, the operations manager, plant superintendent, and corporate communications to ensure that the responsible personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the **ERRP**.

E.7 Environmental Justice Plan

This plan was designed to meet state environmental justice requirements for permitting a geologic storage facility at 16 TAC 5.204(a)(6) and also considers EPA guidance on environmental justice issued in August 2023. The plan presents the results of an energy and environmental justice assessment, discusses project benefits and disbenefits, and describes the stakeholder engagement strategy that Pineywoods CCS, LLC is implementing for the project.

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