TESTING AND MONITORING PLAN
40 CFR 146.90, 40 CFR 146.91
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

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LIST OF ACRONYMS/ABBREVIATIONS

ANSI	American National Standards Institute
AOR	Area of Review
AP	Artificial Penetrations
ASME	American Society of Mechanical Engineers
BH	Bottom Hole
CBL	Cement Bond Log
CCS	Carbon Capture and Storage
CI	Casing Inspection
CO_2	Carbon Dioxide
DAS	Distributed Acoustic Sensing
DH	Downhole
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
gm	Gram
GS	Geologic Sequestration
H_2S	Hydrogen Sulfide
MIT	Mechanical Integrity Test
MMt/y	Millions of Metric Tons per Year
mol%	Percentage of Total Moles in a Mixture made up by One Constituent
NACE	National Association of Corrosion Engineers
P/T	Pressure-Temperature
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture
ppmv	Parts per million volume
psi	Pounds per Square Inch
psia	Pounds per Square Inch, Absolute
QASP	Quality Assurance and Surveillance Plan
RRC	Railroad Commission of Texas
SSTVD	Sub-Sea True Vertical Depth

t/d	Tons per Day
TD	Total Depth
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
VSP	Vertical Seismic Profile

A. Overall Strategy, Approach, and Conceptual Design for Testing and Monitoring

This **Testing and Monitoring Plan** describes how Pineywoods CCS, LLC will monitor the Pineywoods CCS Hub site pursuant to 40 CFR 146.90. Data collected during the implementation of this Plan will be used to demonstrate the wells are operating as planned, the carbon dioxide (CO_2) plume and pressure front are moving as predicted and confirm there is no endangerment to Underground Sources of Drinking Water (USDWs). The monitoring data will also be used to validate and adjust the geological models used to predict the distribution of CO_2 within the storage reservoir to support Area of Review (AOR) reevaluations and a non-endangerment demonstration. Results of the testing and monitoring activities described below may trigger action according to the **Emergency and Remedial Response Plan**.

A.1. Plan Objectives

Pineywoods CCS, LLC's testing and monitoring will cover three main aspects of the geologic sequestration (GS) project during the project injection phase:

1. Well Integrity
2. Operational Parameters
3. Geologic System Changes

Demonstrating the mechanical integrity of the wells in the system is a key aspect of protecting USDWs from endangerment due to injection activities and is a requirement of the Underground Injection Control (UIC) Class VI program. Operational testing and monitoring includes: analysis of the CO_2 stream; continuous monitoring of injection rate, volume, and pressure; corrosion monitoring; and pressure fall-off testing. Monitoring and testing of the geologic system changes includes: ground water quality and geochemical monitoring above the confining zone; direct pressure front monitoring; and direct/indirect CO_2 plume monitoring.

A.2. Plan Strategy and Approach

The **Testing and Monitoring Plan** aims to ensure that sufficient geospatial and monitoring data will be collected and used to validate rigorous numerical modeling and support demonstration of USDW non-endangerment over the life of the project and will be reviewed by Pineywoods CCS, LLC at least every five years. After review, Pineywoods CCS, LLC will submit an amended **Testing and Monitoring Plan** or demonstrate to the UIC Program Director that no amendment to the plan is needed. Pineywoods CCS, LLC recognizes the nexus of data collection and modeling is the primary pathway to exit the UIC permit, define the post-injection site care (PISC) protocols, and close the CO_2 storage site. As such, Pineywoods CCS, LLC is establishing a monitoring program capable of tracking the injected CO_2 and pressure front and developing time-lapse datasets for numerical modeling.

The near surface/subsurface monitoring protocols to be used in the **Testing and Monitoring Plan** at the Pineywoods CCS Hub will provide valuable information to evaluate the performance of the CO_2 injection and storage operations and include:

- Above-zone and shallow USDW fluid sample analyses;
- Above-zone and in-zone direct pressure and temperature measurements;
- Surface to total depth (TD) temperature sensing;
- Through-casing CO_2 saturation profiling; and
- Indirect repeat geophysical imaging.

Pineywoods CCS, LLC plans to drill up to 24 wells (**Table 1**) 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.

Table 1: Pineywoods CCS Hub well summary

Well Types	**Well Acronym**	**CCS System Zone**	**Zone Formation**	**Zone Depth** (ft SSTVS)	**Quantit y**
Shallow Groundwater	**GW (1-7)** GW-1, GW-2, GW-3, GW-4, GW-5, GW-6, GW-7	Shallow USDW	Pliocene *(Chicot Aquifer)*	<575	Up to 7
Deep Observation	**UOB (1-6)** UOB-1, UOB-2, UOB-3, UOB-4, UOB-6	Lowermost USDW	Upper Miocene *(Evangeline Aquifer)*	Base 2,100	6
Above-Zone Observation	**AOB (1-3)** AOB-1, AOB-2, AOB-3	1st Permeable Zone	Lower Miocene 1	4,700-4,810	3
In-Zone Observation	**IPW (1-4)** IPW-1, IPW-2, IPW-3, IPW-4	Reservoir	Lower Frio	7,100-6,000	4
Injection	**PW (1-4)** PW-1, PW-2, PW-3, PW-4	Reservoir	Lower Frio	7,100-6,000	4

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 1: Generalized stratigraphic column identifying the storage reservoir, confining zones, and the deepest USDW at the Pineywoods CCS Hub.

A.3. Baseline Testing and Monitoring

Baseline testing and monitoring for this project includes CO_2 stream characterization, internal and external mechanical integrity, groundwater quality, direct pressure and temperature, indirect CO_2 plume, and hydrogeologic testing (**Table 2**).

CO_2 stream analysis is a critical element of baseline characterization that will provide the chemical profiles, of which the injectate is monitored for, in the observation wells. Pineywoods CCS, LLC will analyze the contents of the CO_2 stream prior to injection, to a sufficient frequency, to yield representative chemical and physical profile data.

Mechanical integrity, internal and external, is a key component of the baseline testing and monitoring program to ensure there are no significant leaks through channels adjacent to the injection well bore (external) and in the injection tubing, packer, or casing (internal) per 40 CFR 146.89(a)(1) and 40 CFR 146.89(a)(2), respectively. A demonstration of internal mechanical integrity will be conducted using an annulus pressure test prior to injection in all injection wells (**See Section F** for details). External mechanical integrity will be demonstrated in all injection and in-zone observation wells once prior to injection, using a distributed temperature sensing (DTS) fiber optic cable mechanical integrity test (MIT). For this plan, DTS will be used in lieu of a temperature log to run MITs.

Groundwater quality and geochemical changes will be monitored in all project wells (**Table 2**) per 40 CFR 146.90(d). Groundwater quality will be measured through the use of permanent downhole and wellhead pressure gauges. These gauges will continuously record and transmit pressure data about the groundwater in the intervals mentioned above and allow for an estimate of the water to be purged prior to sample collection. Groundwater chemistry will be baselined through fluid sampling and analysis in the injection interval of the Lower Frio Formation (PW-1, PW-2, PW-3, PW-4, IPW-1, IPW-2, IPW-3, and IPW-4), the first permeable unit above the caprock in the Lower Miocene 1 Formation (AOB-1, AOB-2, and AOB-3), the lowermost USDW of the Evangeline Aquifer (UOB-1, UOB-2, UOB-3, UOB-4, UOB-5, and UOB-6), and the shallow Chicot Aquifer where up to 7 wells may be placed (GW-1, GW-2, GW-3, GW-4, GW-5, GW-6, and GW-7). Analytes will be tested to create a baseline (see Table 9), representative of the pre-operational groundwater geochemistry, that can be compared to operational geochemistry groundwater monitoring data (see **Section E Groundwater Quality and Geochemistry Monitoring** for details). Groundwater sampling and analysis will occur quarterly, one year prior to injection, in an attempt to capture seasonal variations in the groundwater geochemistry. Carbon isotope analyses will be run for all baseline analyses to enable Pineywoods CCS, LLC to differentiate project and natural/background CO_2. Isotopic analyses will only occur if loss of containment is detected to help verify project containment during injection operations.

Groundwater quality and geochemistry baseline data will help enable verification of containment during injection operations by detecting changes in injection phase data from the baseline data. Changes in the groundwater quality and geochemistry mentioned below can be an indication of loss of containment:

- Total dissolved solids (TDS) increase can indicate native brines have infiltrated the overlying reservoirs.
- Increasing CO_2 concentration and/or decreasing pH can indicate infiltration of CO_2 into monitoring zones.
- Increased reservoir pressure and/or temperature changes may indicate reservoir zone and monitoring zone connectivity.
- Increase in leached constituents (lead, arsenic, etc.) could be due to the presence of CO_2.
- Significant cation and anion signature change could be due to the presence of CO_2.
- Increase of injectate impurities may indicate CO_2 migration into overlying monitoring zones.

Baseline pressure monitoring will occur in the injection, in-zone, above-zone, and deep (lowermost USDW) wells per 40 CFR 146.90(g)(1) and will occur continuously using permanent downhole pressure gauges coupled with wellhead pressure gauges. Direct baseline pressure monitoring in injection and in-zone wells will help reveal natural variations in subsurface pressure. This reservoir zone pressure data will help calibrate model predictions of pressure front propagation and allow for adequate baseline data to help decrease the frequency of false positive and negative loss of containment detection events when compared to injection phase monitoring data. Direct pressure monitoring in the above-zone and deep observation wells will allow for a comparison to operation monitoring pressure data for early detection of containment loss due to increased pressures from potential out-of-zone reservoir brine and/or CO_2.

Indirect CO_2 plume baseline monitoring will occur at the Pineywoods CCS Hub per 40 CFR 146.90(g)(2). Pineywoods CCS, LLC plans to implement indirect CO_2 plume monitoring using DTS, PNC logging, and repeat geophysical 3D DAS VSP surveys or a similar geophysical technology. Baseline data will be acquired prior to injection for comparison to injection phase monitoring data.

PNC logging tools can detect elevated oxygen around the wellbore in the rock formation and therefore the presence of CO_2. PNC logging will be conducted once prior to injection in all injection, in-zone, above-zone, and deep observation wells. This baseline logging data will allow for comparison to injection phase monitoring data to determine the vertical location of CO_2 within the injection and in-zone wells, and for early detection of containment loss for above-zone and deep observation wells. During injection, PNC will only be run in the injection wells, any wells with CO_2 breakthrough, and in any well with monitoring data indicating loss of containment. For the zones above the caprock, PNC logging will be used as a verification technique to help prove the absence of CO_2. Groundwater sampling and analysis will also be used to verify elevated levels of CO_2 and determine if the elevated CO_2 is project related.

DTS data will be used to indirectly monitor the location of the CO_2 saturation plume. Differences in the reservoir temperature and injectate stream temperature will be detected allowing for interpretation of the vertical location of the CO_2 plume near the wellbore. As mentioned above, all injection and in-zone wells will contain DTS on the long string casing and record continuous temperature measurements after well construction and prior to injection. Injection phase monitoring data will be compared to baseline data to determine vertical extent of CO_2 in the injection wells (and eventually the in-zone observation wells), CO_2 breakthrough in the in-zone observation wells, and early detection for containment loss in the wells above the primary confining unit. Reservoir zone intervals taking CO_2, detected via DTS, will then be used to calibrate reservoir models for better prediction of CO_2 saturation plume behavior through time.

Hydrogeologic testing, which includes pressure fall-off testing, will be conducted once prior to injection at each injection well. This data will be used to better understand any injectivity heterogeneity within the reservoir and to better predict plume movement in reservoir models. During the injection phase, hydrogeologic test data can be compared to DTS and PNC logging data for confirmation of the injection zone interval taking fluid and any potential changes in the reservoir injectivity as a result of injection.

All necessary data will be collected during the pre-injection phase (**Table 2**) to represent the in-situ properties prior to injection. Data collected during the injection phase will then be compared to pre-injection phase baseline measurements to ensure containment and protection of groundwater resources.

Table 2: Pre-injection testing and monitoring technologies, frequencies, and locations.

Monitoring Parameter	Technology/Test	Baseline Phase Frequency (1 year)	Location
Internal MIT	Annulus Pressure Test	1 Prior to Injection	PW (1-4)
External MIT	1) DTS 2) Ultra Sonic CBL 3) Electromag. CI Logs	1 Prior to Injection	PW (1-4), IPW (1-4)
Groundwater Quality	1) Fluid S&A 2) BH P Gauges	1) Quarterly 2) Continuous	PW (1-4), IPW (1-4), AOB (1-3), & UOB (1-6)
Direct Pressure Monitoring	1) P Gauges – Tubing 2) Downhole P Gauges	Continuous	PW (1-4), IPW (1-4), AOB (1-3), & UOB (1-6)
Indirect CO_2 Plume Monitoring Techniques	DTS	1 Year Prior to Injection	PW (1-4), IPW (1-4)
	PNC Logging	1 Prior to Injection	PW (1-4), IPW (1-4), AOB (1-3), UOB (1-6)
	1) Repeat 3D DAS VSP *OR* 2) Seismic		1) PW (1-4), and IPW (1-4) *OR* 2) Surface or In-Well
Hydrogeologic Testing	Pressure Fall-Off Testing		PW (1-4)

A.4. Conceptual Monitoring Network Design

This plan describes injection phase components of the geologic testing and monitoring program, which includes hydraulic, geophysical, geochemical, and physical components for characterizing the complex fate and transport processes associated with CO_2 injection. The injection wells and in-zone observation wells will be monitored to characterize reservoir pressure, monitor CO_2 transport response, and guide operational and regulatory decision-making. **Figure 2** shows a simplified layout of the storage complex depicting the location of testing and monitoring equipment.

Above-zone observation wells will monitor the first permeable zone above the primary caprock for pressure, temperature, and fluid chemistry changes for early detection of containment loss. In-zone observation wells, in combination with the above-zone observation wells, will provide the first indication of unanticipated containment loss. Pineywoods CCS, LLC's characterization of the subsurface revealed project risks within the AOR that will be addressed in this plan. Risks to USDWs include mapped faults (seismic and faults from literature), Artificial Penetrations (APs), and project well penetrations (**Figure 3**). To mitigate these risks, Pineywoods CCS, LLC has implemented a well- and seismic-based monitoring plan to track the CO_2 and pressure plume evolution and ensure protection of groundwater resources. Monitoring technology in injection and

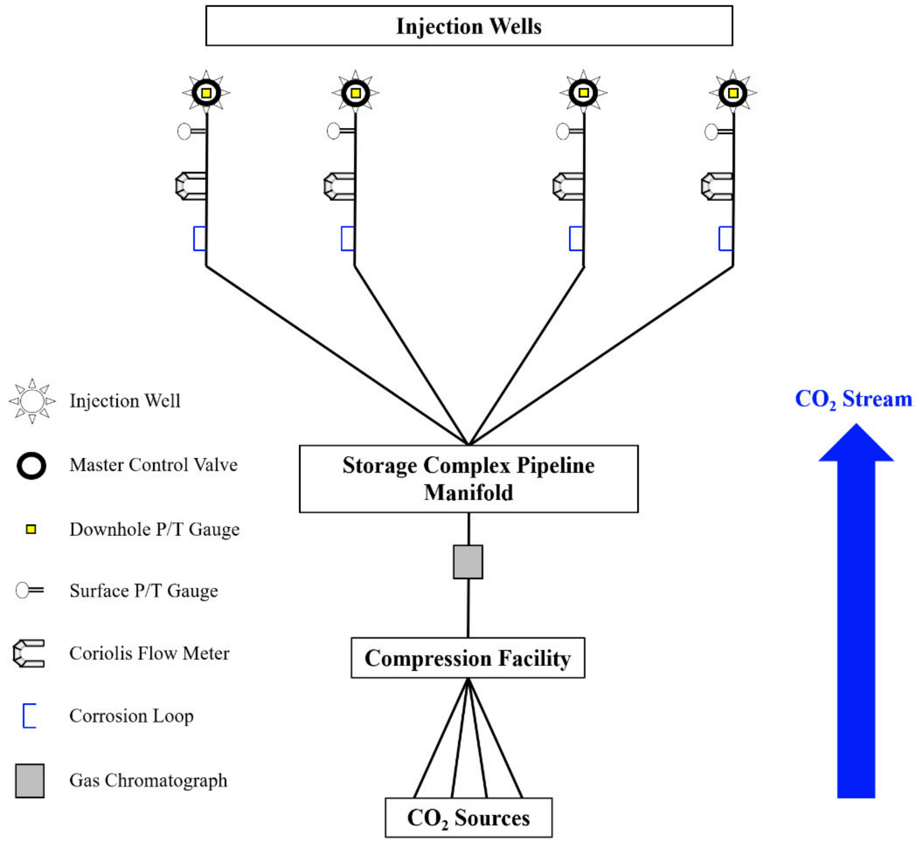

Figure 22: Simplified layout of the storage complex depicting the location of testing and monitoring equipment.

in-zone observation wells will help track the CO_2 and pressure plume front movement through time.

The above-zone observation wells will be completed in the permeable unit of the Lower Miocene 1 Formation to detect physical and chemical changes in the groundwater to ensure early detection of containment loss in order to protect USDWs. All observation wells will have direct monitoring of pressure and temperature in multiple zones. Protection of USDWs, required by the EPA's UIC Class VI GS Rule (75 FR 77230), is a primary objective of the monitoring program at the Pineywoods CCS Hub as demonstrated by the three above-zone, six deep, and up to 7 shallow USDW observation wells. Fluid samples will be collected from these wells in the Lower Miocene 1 (above-zone) and Evangeline Freshwater Aquifer (lowermost USDW in Liberty and Hardin Counties, Texas). The three above-zone observation wells will provide early detection of any out-of-zone CO_2, allowing Pineywoods CCS, LLC to demonstrate non-endangerment to USDW or groundwater aquifers. The associated networks of above-zone and shallow ground water monitoring locations are designed to provide: 1) a thorough assessment of baseline conditions at the site, and 2) spatially distributed monitoring locations near point sources that can be routinely sampled throughout the life of the project.

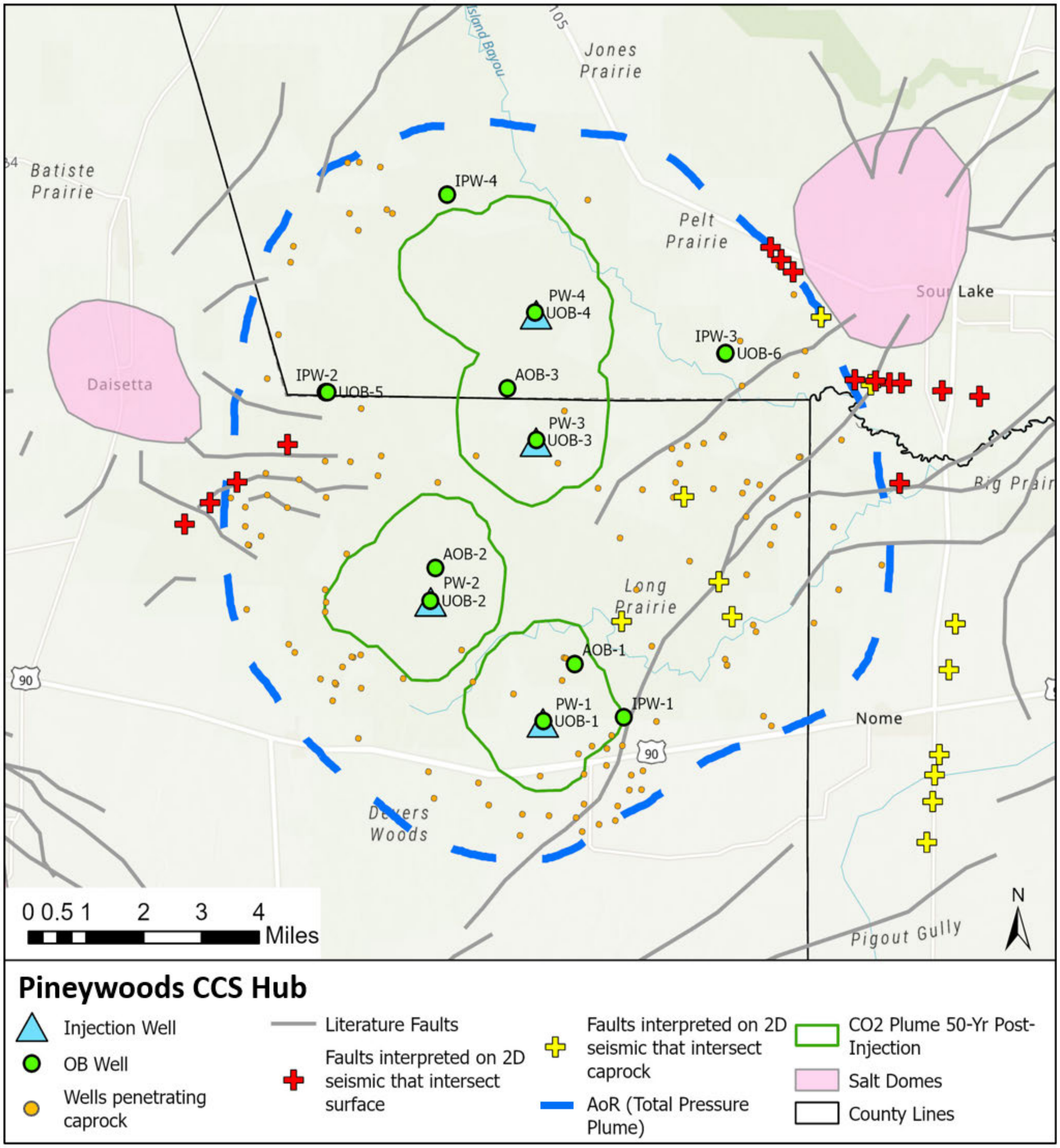

Figure 3: Map of Pineywoods CCS Hub showing maximum extent of the pressure plume (AOR) and the proposed injection and observation well locations. Observation wells are broken up into 3 categories: In-Zone Observation (IPW), Above-Zone Observation (AOB), and Deep USDW observation (UOB).

Table 3: Pineywoods CCS Hub testing and monitoring frequencies for all project phases.

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	<u>Internal</u> *Annulus*	Pressure Test	1 Prior to Injection	N/A	*N/A*
		Pressure Monitoring	N/A	Continuous	Continuous
	<u>External</u> *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

Observation wells have been strategically placed to mitigate the highest risks to USDWs within the AOR. In-zone wells (IPW-1, IPW-2, IPW-3, and IPW-4) have been strategically placed to image the CO_2 plume and track the pressure front evolution. These wells have been placed outside the maximum CO_2 plume extent but within the maximum pressure front extent and act as sentry wells bounding the CO_2 plume. Locations of Shallow groundwater observations well will be determined based on final locations of observation wells. Final observation well locations will be determined after completion of a 3D DAS VSP feasibility study, which is anticipated prior to permit issuance. Monitoring data from these wells will be used to update and history match the pressure response in reservoir models. IPW-1 is placed to the east of PW-1 at the maximum extent of the CO_2 plume, 50 years post injection, and close to the southern bounding fault. This well will allow for monitoring of fault related reservoir pressure responses. IPW-2 is placed west of PW-3 and PW-4. This well will monitor any salt dome and faulting related reservoir pressure responses should they occur and ensure the CO_2 plume is not reaching the salt dome extent and the pressures are not reaching fracture or fault re-activation levels in this higher risk of containment area. IPW-3 is placed east of PW-3 and PW-4 and monitors similar risks as IPW-2 but to the east of the injection wells. IPW-4 is placed north of PW-3 and PW-4 at the edge of the 50-year post-injection CO_2 plume extent. This well will ensure the CO_2 plume extent is not reaching the northern faults and pressures are acting as predicted.

The above-zone (AOB-1, AOB-2, AOB-3) observation wells will monitor conditions in the first permeable zone above the primary caprock to ensure containment of reservoir brine and CO_2. High pressure zones around the injection wells with natural (faults) or artificial penetrations pose the highest risk to containment and USDWs (Figure 3). Pineywoods CCS, LLC has therefore placed above-zone wells near the injection wells for early detection of containment loss. AOB-1 is placed north-northeast of PW-1 near three artificial penetrations. AOB-2 is placed north of PW-2 to monitor the high pressures around the well. AOB-3 is located between PW-3 and PW-4 to monitor for loss of containment in the high-pressure zones around the injection wells.

The six deep (lowermost USDW) observation wells (UOB-1, UOB-2, UOB-3, UOB-4, UOB-5, and UOB-6) have been placed to ensure containment in the AOR and provide evidence for the non-endangerment demonstration required for site closure. UOB-1, UOB-2, UOB-3, and UOB-4 are placed on each injection well pad to monitor the USDW directly above and around each injection well. UOB-5 and UOB-6 are placed at the easternmost and westernmost in-zone observation wells to ensure containment of USDWs around the salt domes and faults to the east and west of the project.

Up to seven shallow groundwater observation wells will be placed at strategic locations as backup monitoring should Pineywoods CCS, LLC need to monitor the shallow groundwater. Wells have not been placed at this time, but placement will consider potential contamination near the AOR, high-risk areas such as faults and high pressures, and community concerns. Minimal surface disruption is anticipated by completing multiple project wells on a single well pad, where possible.

Table 4: Injection phase testing and monitoring frequencies and locations

<table>
<tr><th>Monitoring Parameter</th><th>Technology/Test</th><th>Injection Phase Frequency (30 years)</th><th>Location</th></tr>
<tr><td>Injectate Chemical Characteristics</td><td>1) Gas Chromatograph
2) Injectate Sampling & Analysis</td><td>1) Continuous
2) Annually</td><td>Prior to Injection Wells Manifold (PW-2)</td></tr>
<tr><td>Injection Rate</td><td>Mass Flow Meter</td><td>Continuous</td><td>Each Injection Well Pad: PW (1-4)</td></tr>
<tr><td>Injection Physical Characteristics</td><td>1) P Gauges – Tubing
2) DH P Gauges</td><td>Continuous</td><td>PW (1-4)</td></tr>
<tr><td>Annulus Pressure Monitoring</td><td>P Gauge - Annulus</td><td>Continuous</td><td>PW (1-4)</td></tr>
<tr><td>Annulus Volume Added</td><td>Fluid Tank Volume Meter</td><td>Continuous</td><td>PW (1-4) Well Pads</td></tr>
<tr><td>Internal MIT</td><td>P Gauge - Annulus</td><td>Continuous</td><td>PW (1-4)</td></tr>
<tr><td>External MIT</td><td>DTS</td><td>1 MIT Annually</td><td>PW (1-4), IPW (1-4)</td></tr>
<tr><td>Corrosion</td><td>Coupon Analysis</td><td>Quarterly</td><td>PW (1-4)</td></tr>
<tr><td>Groundwater Quality & Geochemistry</td><td>1) Fluid S&A[1]
2) BH P Gauges</td><td>1) Quarterly for 1st Year, Then Annually
2) Continuous</td><td>IPW (1-4), AOB (1-3) & UOB (1-6)</td></tr>
<tr><td>Direct Pressure Monitoring</td><td>1) P Gauges – Tubing
2) DH P Gauges</td><td>Continuous</td><td>PW (1-4), IPW (1-4), AOB (1-3), & UOB (1-6)</td></tr>
<tr><td rowspan="3">Indirect CO_2 Plume Monitoring Techniques</td><td>DTS</td><td>Continuous</td><td>PW (1-4), IPW (1-4)</td></tr>
<tr><td>PNC Logging[2]</td><td rowspan="3">3 Years After Injection, 1 Every 5 Years Thereafter</td><td>PW (1-4), IPW (1-4)</td></tr>
<tr><td>1) Repeat 3D DAS VSP
OR
2) Seismic</td><td>1) PW (1-4), and IPW (1-4)
OR
2) TBD</td></tr>
<tr><td>Hydrogeologic Testing</td><td>Pressure Fall-Off Testing</td><td>PW (1-4)</td></tr>
</table>

[1]Sampling & analysis frequencies may be reduced based on project-specific benchmarks that will be defined from baseline monitoring data and/or injection phase monitoring data.

[2]PNC logging or equivalent will only occur in wells with CO_2 breakthrough or wells with detected containment loss at the frequency specified in the table above.

A.5. Quality Assurance Procedures

A **Quality Assurance and Surveillance Plan (QASP)** for all testing and monitoring activities, required pursuant to 40 CFR 146.90(k), is provided in **Appendix A** to this **Testing and Monitoring Plan**.

A.6. Reporting Procedures

Pineywoods CCS, LLC will report the results of all testing and monitoring activities to the UIC Program Director in compliance with the requirements under 40 CFR 146.91 and 16 TAC 5.207. All reports will be certified in compliance with 16 TAC 5.207(d) and signed by a responsible corporate officer or a duly authorized representative in accordance with 16 TAC 5.207(c)(1). The following reporting requirements apply to the Pineywoods CCS Hub.

<u>24-Hour Notification of an Event and 5-Day Report</u>. Pineywoods CCS, LLC will notify the UIC Program Director via phone as soon as practicable but within 24 hours of discovery of the following events (40 CFR 146.91(c)):

- Discovery of any significant pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the geologic storage reservoir;
- Any evidence that the injected CO_2 stream or associated pressure front may cause endangerment to a USDW;
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
- Any triggering of a shut-off system downhole or at surface; or
- Any failure to maintain mechanical integrity.

Within 5 days of discovery, Pineywoods CCS, LLC will follow-up with a written report to the UIC Program Director. The report will include the following: description of the noncompliance and its cause, period of noncompliance including exact dates and times, if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance (16 TAC 5.207(a)(2)(A)).

<u>30-Day Notification of Planned Activity and Results Reporting</u>. Pineywoods CCS, LLC will provide written notice to the UIC Program Director at least 30 days in advance of the following activities at an injection well (40 CFR 146.91(d)):

- Any planned well workover;
- Any planned stimulation activities other than stimulation for formation testing conducted under the initial collection of geologic information; or
- Any other planned test of the injection well by Pineywoods CCS, LLC.

Within 30 Days of a well workover, MIT, or other injection well test, Pineywoods CCS, LLC will submit the results to the UIC Program Director (40 CFR 146.91(b); 16 TAC 5.207(a)(1) and 5.207(a)(2)(B)). Results of an internal MIT will be submitted using RRC Form H-5 (16 TAC 5.207(b)(1)).

<u>Semi-Annual Testing and Monitoring Report</u>. Pineywoods CCS, LLC will submit a semi-annual report to the UIC Program Director that will include the following (40 CFR 146.91(a); 16 TAC 5.207(a)(2)(C)):

- Summary of well head pressure monitoring;
- Any changes to the source as well as physical, chemical, and other relevant characteristics of the CO_2 stream;
- Monthly average, minimum, and maximum values for the operating injection pressure, injection flow rate, temperature, injection volume or mass, and annular pressure (results of injection pressure and injection rate monitoring of

each injection well must be reported on RRC's Form H-10 per 16 TAC 5.207(b));
- Monthly annulus fluid volume added;
- Description of any event that significantly exceeds operating parameters for annulus or injection pressure;
- Description of any event that triggers a shut down device and the response taken;
- The monthly volume or mass of CO_2 injected over the current reporting period and cumulative volume or mass of CO_2 injected since the start of injection;
- Results of monitoring prescribed under 16 TAC 5.206(e); and
- Any data collected or notable results from the implementation of the **Testing and Monitoring Plan.**

Annual Geologic Storage Facility Report. Pineywoods CCS, LLC will submit an annual report to the UIC Program Director that will include the following (16 TAC 5.207(a)(2)(D)):

- Corrective action performed;
- New wells installed and type, location, number, and information required in 16 TAC 5.203(e);
- Re-calculated AOR or statement signed by appropriate company official confirming that monitoring and operational data supports the current delineation of the AOR;
- Updated area for which the operator has a good faith claim to the necessary and sufficient property rights to operate the geologic storage facility;
- Tons of CO_2 injected; and
- Any other information required by the permit.

Recordkeeping

Per 40 CFR 146.91(f) and 16 TAC 5.207(e), Pineywoods CCS, LLC will retain the following records for the time specified:

- All site characterization data and data collected for the permit application will be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure;
- Data on the nature and composition of all injected fluids will be retained for at least 10 years after site closure;
- Any monitoring data collected through the **Testing and Monitoring Plan** will be retained for at least 10 years after it is collected;
- Well plugging reports and all PISC data will be retained for at least 10 years after site closure; and
- All documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility through site closure.

B. Carbon Dioxide Stream Analysis

Pineywoods CCS, LLC will analyze the CO_2 stream during the injection phase to collect representative characteristic data on the chemical composition of the CO_2 stream, pursuant to 40 CFR 146.90(a). Pineywoods CCS, LLC expects multiple sources of CO_2 from the region, with additional sources to be added throughout the life of the project. Each source will have a different gas stream composition based on the source's capture process, and the composition of the final injected gas stream will change depending on which sources are operational and not undergoing maintenance. As a result, 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. The CO_2 stream coming into the storage site is expected to have a mol% CO_2 concentration of at least 96% with other chemical constituents as seen in **Table 5**.

A continuous gas chromatograph and sampling port will be installed at PW-2 prior to the storage complex pipeline manifold downstream of all CO_2 sources to ensure the quality meets specification and that Pineywoods CCS, LLC can isolate the delivery of the stream in the event it is out of specification (e.g., high water, H_2S, etc.).

B.1. Sampling Location and Frequency

Pineywoods CCS, LLC will continuously analyze the CO_2 stream during the injection phase to collect representative chemical characteristic data. Baseline parameters will be established at the start of injection, and monitoring will occur continuously throughout the injection phase using a gas chromatograph. This chromatograph will be placed downstream of all source points near PW-2 prior to the storage complex pipeline manifold. Sampling and monitoring will occur continuously at 30-minute intervals. To supplement continuous gas chromatograph monitoring, physical samples will also be collected from a sampling port annually for H_2S and total sulfur; this sampling port will be near the gas chromatograph downstream of all CO_2 sources and near PW-2 prior to the pipeline manifold. Pineywoods CCS, LLC will report the results of the CO_2 stream analysis in semi-annual operational reports (see **Section A.6** above).

In the event of unplanned disruptions to permitted injection activities that may affect the chemical composition of the final CO_2 stream, Pineywoods CCS, LLC will increase the frequency of CO_2 stream reporting to the UIC Program Director to confirm there are no significant changes and injection is continuing to operate as permitted.

B.2. Analytical parameters

Pineywoods CCS, LLC will analyze the CO_2 stream for the constituents identified in **Table 5** using a gas chromatograph and through physical sampling. The list of parameters will be altered if analysis from the CO_2 stream demonstrates additional constituents to be considered. Any additional details concerning analysis of the CO_2 stream can be found in the **Quality Assurance and Surveillance Plan (QASP)**, which is attached as **Appendix A**. Amendments to this plan must be approved by the UIC Program Director.

B.3. Sampling Methods

The CO_2 stream will be sampled continuously with an on-site gas chromatograph. Physical samples will also be taken through a sampling port near the gas chromatograph at PW-2. For more information refer to the **QASP** in **Appendix A**.

Table 5: Summary of analytical parameters for CO_2 stream.

Component[1]	Specification	Unit
Minimum CO_2	>96	Mol%, dry basis
No Free Liquids		
Carbon Monoxide (CO)	< 100	ppmv
Water (H_2O)	< 20	lb./MMSCF
Total Hydrocarbons	< 2	Mol%, dry
Amine	< 20	ppmv
Ammonia (NH_3)	< 40	ppmv
Total Organic Compounds	< 50	ppmv
Hydrogen Sulfide (H_2S)	< 50	ppmv
SOx	< 100	ppmv
Total Sulfur	< 100	ppmv
NOx	< 100	ppmv
Glycol	< 1	ppmv
Hydrogen (H_2)	< 1	Mol%
Inert Gasses (Non-Condensable)	< 4	Mol%, dry
Oxygen (O_2)	< 20	ppmv
Particulate Matter	< 1	ppmw

[1]This list is subject to change based on source injectate stream composition results.

C. <u>Continuous Recording of Operational Parameters</u>

Pineywoods CCS, LLC will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream pursuant to 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Pineywoods CCS, LLC will monitor injection operations using a distributive process control system. The surface facility equipment and control system will limit maximum instantaneous flow to 4,110 t/d and/or limit the wellhead pressure to 2,220 psia, which corresponds to well below the regulatory requirement to not exceed 90% of the injection zone's fracture pressure, 3,750 psia (40 CFR 146.88(a)). The maximum instantaneous injection rate is 1.5 MMt/y, per well. See **Section D.3.1 of the Application Narrative** for more detail on operational conditions.

All critical system parameters (e.g., pressure, temperature, and flow rate) will have continuous electronic monitoring with signals transmitted back to a master control system. The system will automatically sound an alarm and shutdown operations should specified control parameters exceed their normal operating range at any time. Pineywoods CCS, LLC supervisors and operations personnel will have the capability to monitor and control all operations remotely with this system.

Pineywoods CCS, LLC will perform the activities identified in **Table 6** to monitor operational parameters. Surface and downhole pressure and temperature instruments will be calibrated annually over the full operational range using ANSI or other recognized standards. Bottom hole (BH) pressure gauges shall have a drift stability of less than 3 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least one every five seconds. Temperature sensors will be accurate to within one degree Celsius. Downhole and surface pressure gauge specifications are described in more detail in the **QASP**.

Injection rate (i.e., injection flow) will be monitored with Coriolis mass flow meters. The flow meters will be located on each injection well pad. The flow meter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flow meter will be calibrated for the entire expected range of flow rates. See **QASP** for additional details.

Table 6: Sampling methods, locations, and frequencies

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection Pressure	1) Tubing P Gauge 2) Downhole P Gauge[1]	1) PW (1-4), IPW (1-4) 2) PW (1-4), IPW (1-4)	5 sec. / 4 hours	5 mins. / 4 hours
Injection Rate	Coriolis Mass Flow Meter	PW (1-4)	5 sec. / 4 hours	5 mins. / 4 hours
Injection Volume	Coriolis Mass Flow Meter	PW (1-4)	5 sec. / 4 hours	5 mins. / 4 hours
Annular Pressure	Annular P Gauge	PW (1-4)	5 sec. / 4 hours	5 mins. / 4 hours
Annulus Fluid Volume	Fluid Tank Volume Meter	PW (1-4)	5 sec. / 4 hours	5 mins. / 4 hours
Injection Temperature Monitoring	1) DTS 2) Tubing P Gauge 3) Downhole P Gauge[1]	1) PW (1-4), IPW (1-4) 2) PW (1-4), IPW (1-4) 3) PW (1-4), IPW (1-4)	1) 10 min. / 10 min. 2) 5 sec. / 4 hours 3) 3.5 sec. / 4 hours	1) 10 min. /10 min. 2) 5 sec. / 4 hours 3) 3.5 sec. / 4 hours

[1]All downhole gauges will be placed above the packer and ported through it to the respective well monitoring zone (see Table 1).

C.1. Injection Rate, Volume, and Pressure Monitoring

Pineywoods CCS, LLC will continuously monitor injection rate, volume, and pressure for each injection well pursuant to 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Storage site injection rate and volume will be monitored using Coriolis mass flow meters that will be located based on manufacturer specifications: at each well pad, immediately upstream of each injector wellhead. Individual Coriolis mass flow meters will be used at the storage site to record each injection well's rate and volume. Pineywoods CCS, LLC will include measurements to account for flow rate of injected fluid, concentration of the fluid stream, injectate density, injectate temperature, and energy inputs required for operation. Flow meters will be temperature and pressure compensated and calibrated according to manufacturer specifications. Flow rate data will be used to determine the cumulative mass of CO_2 injected and to confirm compliance with operational requirements of the Class VI UIC permit.

Injection pressure will be continuously monitored using wellhead and downhole pressure gauges. Each injection well will be equipped with permanent downhole pressure gauges that will continuously monitor the injection zone pressure to ensure that the injection zone pressures do not exceed 90 percent of the reservoir fracture pressure as required by 40 CFR 146.88(a) and will ensure Pineywoods CCS, LLC is compliant with operating conditions. Additionally, each injection well will be equipped with a wellhead pressure logger that will ensure Pineywoods CCS, LLC maintains surface pressures below the maximum allowable pressure for each well. This pressure limit is equal to the top perforation or completion depth, in true vertical depth, multiplied by the difference between the injection gradient and the injectate fluid gradient.

C.2. Annulus Pressure & Fluid Volume Monitoring

Pineywoods CCS, LLC will use the procedure below to monitor annular pressure to limit the potential for any unpermitted fluid movement into or out of the injection well annulus:

- The annulus between the tubing and the long string of casing will be filled with brine. Brine will meet specified parameters such as a brine specific gravity, brine density, and annulus hydrostatic gradient. The brine will contain a corrosion inhibitor.
- The surface annulus pressure will be kept within a range of 375 psia ± 125 psia.
- During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of an estimated 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.
- The pressure within the annular space, over the interval above the packer to the confining layer, will always be greater than the pressure of the injection zone formation.
- The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

Figure 4 shows the process instrument diagram used for injection well annulus protection systems. The annular monitoring system will consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using compressed nitrogen.

The annular pressure between the tubing and the long-string casing will be maintained at a higher pressure than the injection pressure, at bottom hole conditions, during injection, and will be monitored by the Pineywoods CCS, LLC control system gauges. The annulus head tank pressure will be controlled by pressure regulators or pumps; one set of regulators or pumps will be used to maintain pressure above injection pressure, if needed by adding compressed nitrogen or CO_2, and the other set will be used to relieve pressure, if needed, by venting gas or fluid from the annulus head tank. Any changes to the composition of annular fluid will be submitted to the UIC Program Director for approval.

If system communication were to be lost for greater than 60 minutes, project personnel will observe and monitor manual gauges in the field every eight hours or once per shift for both wellhead surface pressure and annulus pressure, while also recording hard copies of the data until communication is restored.

Average annular pressure, annulus tank fluid level, and volume of fluid added or removed from the system will be recorded daily and reported as monthly averages in the semi-annual report (see **Section A.6** above).

C.3. Injection Temperature Monitoring

Pineywoods CCS, LLC will continuously monitor injection temperature at the surface and downhole for each injection well. The wellhead pressure logger will also continuously measure and record wellhead temperature and be used as a backup should the DTS and/or permanent downhole gauges fail. Pineywoods CCS, LLC will supply two downhole temperature measurements: permanent downhole temperature gauges and DTS fiber optic wire.

In-well pressure and temperature measurements will be taken using permanent downhole gauges. Fiber optic technology will be implemented in the injection and observation wells. Each injection well will contain a permanent temperature gauge proximate to the packer that will measure the temperature of the injectate as it reaches the injection zone. The DTS fiber optic wire will be run from the surface to the well’s total depth (TD). This technology will continuously measure the temperature in the formations outside the casing throughout the entire well column.

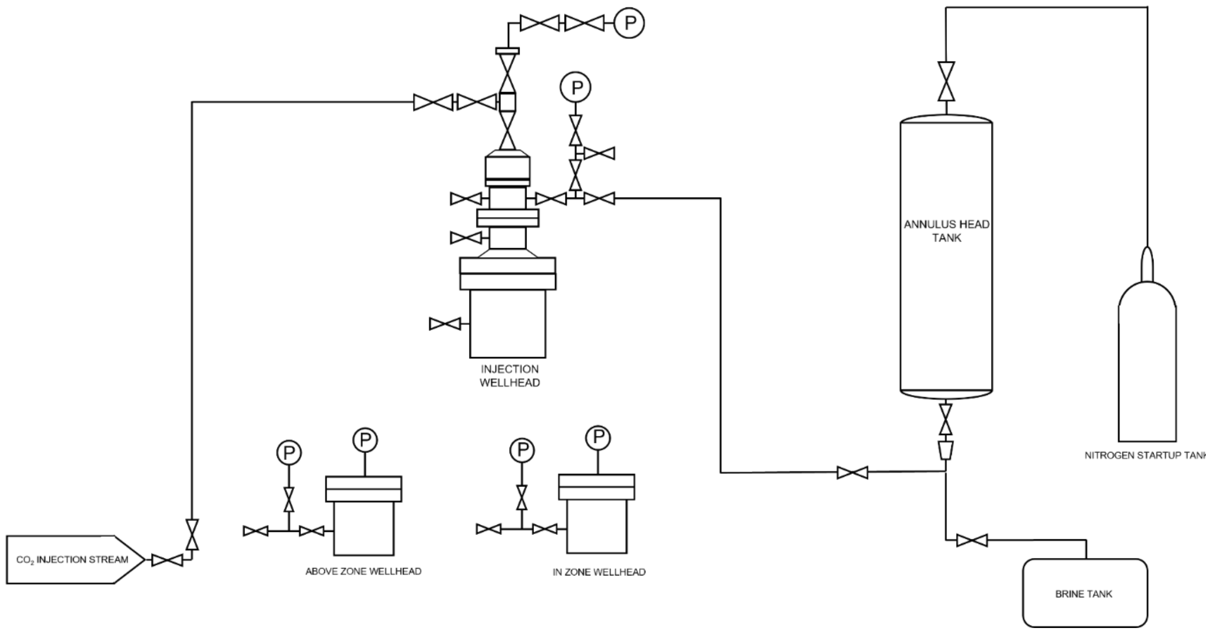

Figure 4. Annular monitoring system

D. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), Pineywoods CCS, LLC will monitor well materials during the injection phase for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Pineywoods CCS, LLC will monitor corrosion using corrosion coupons and collect samples according to the description below.

D.1. Monitoring Location and Frequency

Corrosion monitoring will occur on a quarterly basis during the injection phase, by the following dates each year:

- Three months after the date of injection authorization;
- Six months after the date of injection authorization;
- Nine months after the date of injection authorization; and
- Twelve months after the date of injection authorization.

Pineywoods CCS, LLC will monitor for corrosion using corrosion coupons in a closed loop system.

D.2. Sample Description

Samples of materials used in the construction of compression equipment, pipeline, and any wells which encounter CO_2 will be included in the corrosion monitoring program. The samples will be comprised of those items listed in **Table 7**. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 7: List of equipment coupons with material of construction

Equipment Coupon	Material of Construction
Pipeline	API 5L X42 PSL2, API 5L X52 PSL2 API 5L X60, API 5L X65 PSL2 API 5L or X70 PSL2 carbon steel
Long String Casing	47 lb./ft, L-80, LTC & 47 lb./ft, CR13-L80, Premium Connection
Injection Tubing	17 lb./ft, CR13-L80 or Coated L80, Premium Connection
Wellhead	Carbon or alloy steel or Stainless steel
Packers	13Cr80/ VAM Coupling

*Refer to **Section C and Section D of the Application Narrative** for specific elevations for each injection well

D.3. Sample Exposure

Each sample will be attached to an individual holder and then inserted into a flow-through pipe arrangement (**Figure 5**) attached to the pipeline. The corrosion monitoring systems will be located upstream of the wellhead and downstream of the injection well control valve (**Figure 2**). The corrosion loop system routes a parallel stream of high-pressure CO_2 from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. The loop will allow for corrosion inspection and injection to occur simultaneously. The corrosion equipment is placed close to the wellhead prior to the Coriolis mass flow meter to provide representative exposure of the CO_2 composition, temperature, and pressures that will be observed at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design plan and will allow for continuation of CO_2 injection during sample removal.

D.4. Sample Monitoring and Handling

Corrosion coupons will be handled and evaluated for corrosion using the NACE RP0775-2018 (NACE, 2018) standard or a similarly accepted standard practice for preparing, cleaning, and evaluating corrosion test specimens The coupons will be photographed, visually inspected (under minimum of 10x power), dimensionally measured to within 0.0001 inch, and weighted to within 0.0001 gm. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration of exposure (i.e., weight loss method). Corrosion monitoring is implemented in this project as a loss of containment prevention measure.

Casing and tubing will be evaluated for corrosion on an as-needed basis by running wireline casing inspection logs. Furthermore, wireline tools can be lowered into the well to directly measure properties of the well tubulars that indicate corrosion. These tools will provide circumferential images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.

The different types of logs that may be used to monitor and assess the condition of well tubing and casing include:

- Mechanical casing evaluation tools, referred to as calipers, have multiple articulated arms attached to the tool that measure the inner diameter of the tubular as the caliper is raised or lowered through the well.
- Ultrasonic tools, which are capable of measuring wall thickness in addition to the inner diameter of the well tubular and can also provide information about the outer surface of the casing or tubing.
- Electromagnetic tools, which are capable of distinguishing between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated.

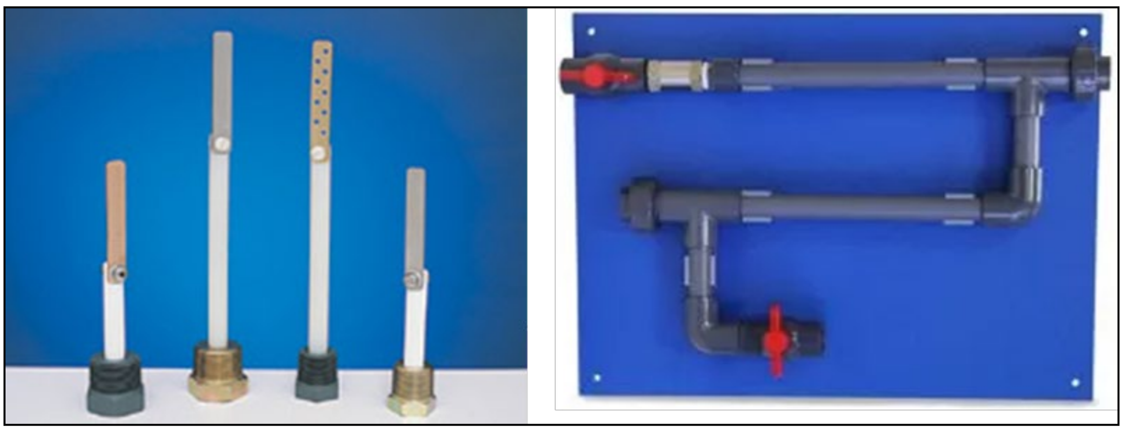

Figure 5: (Left) Example of corrosion coupon holders. (Right) Flow through pipe arrangement example.

E. <u>Groundwater Quality and Geochemistry Monitoring</u>

Pineywoods CCS, LLC will monitor groundwater quality and geochemistry in the reservoir, the first permeable unit above the caprock, and lowermost USDW during the pre-injection and injection phases pursuant to 40 CFR 146.90(d). During the post-injection phase of the project, groundwater quality and geochemistry will be monitored in only the first permeable zone above the caprock and the lowermost USDW. Groundwater geochemistry monitoring will be conducted using direct fluid sampling and analysis. Groundwater quality will be monitored directly using downhole P gauges.

Baseline monitoring will be conducted in all project wells completed in the Lower Frio Formation (primary injection zone), the Lower Miocene 1 Formation (first permeable zone above the caprock), and the Upper Miocene Evangeline Aquifer (lowermost USDW) to understand groundwater fluid chemistry and quality prior to injection (**Table 2**). This section describes groundwater monitoring during the injection phase of the project with a focus on the following zones:

- Lower Frio Formation (Injection Zone);
- The Lower Miocene 1 (first permeable zone above the Anahuac Formation confining zone); and
- Evangeline Freshwater Aquifer (lowermost USDW).

During the injection phase of the project, in-zone groundwater quality monitoring will only occur in the in-zone observation wells (IPW-1, IPW-2, IPW-3, IPW-4). In-zone monitoring results, coupled with results from above-zone observation wells installed directly above the primary confining zone (Anahauc Formation) in the first permeable unit (Lower Miocene 1), will provide the first evidence of any loss of containment. If a loss of containment is detected and verified, a modeling evaluation of any observed injectate migration above the confining zone will be used to evaluate the magnitude of containment loss and generate bounding predictions regarding anticipated impacts on shallower intervals, USDW aquifers, and ecology.

E.1. Monitoring location and frequency

The proposed locations of up to seven shallow groundwater, six deep, three above-zone, and four in-zone observation wells are spatially displayed in **Figure 3**. These locations are subject to change based on land/pore space acquisition. The planned monitoring technologies, locations, depth intervals, and frequencies for geochemical monitoring are displayed in **Table 8** below.

Table 8: Monitoring geochemical and physical changes.

<table>
<tr><th>Target Formation</th><th>Monitoring Activity</th><th>Monitoring Location(s)</th><th>Spatial Coverage</th><th>Frequency</th></tr>
<tr><td rowspan="2">Evangeline Freshwater Aquifer
(Lowermost USDW)</td><td>Geochemical Monitoring:
Direct Fluid Sampling</td><td rowspan="2">Deep observation wells [UOB-1, UOB-2, UOB-3, UOB-4, UOB-5, UOB-6]</td><td rowspan="2">6 Well Locations

Vertical (ft. SSTVD):
UOB-1: ~2,275
UOB-2: ~2,175
UOB-3: ~2,075
UOB-4: ~1,975
UOB-5: ~2,075
UOB-6: ~1,975</td><td>*Quarterly for first year, **annually thereafter.</td></tr>
<tr><td>Physical Monitoring:
Downhole P Gauges</td><td>Continuous</td></tr>
<tr><td rowspan="2">Lower Miocene 1
(First permeable unit over confining zone)</td><td>Geochemical Monitoring:
Direct Fluid Sampling</td><td rowspan="2">Above-zone observation wells [AOB-1, AOB-2, AOB-3]</td><td rowspan="2">3 Well Locations

Vertical (ft. SSTVD):
AOB-1: ~5,010
AOB-2: ~4,730
AOB-3: ~4,340</td><td>*Quarterly for first year, **annually thereafter</td></tr>
<tr><td>Physical Monitoring:
Downhole P Gauges</td><td>Continuous</td></tr>
<tr><td>Lower Frio
(Injection Interval)</td><td>Geochemical Monitoring:
Direct Fluid Sampling</td><td>In-Zone Observation Wells
[IPW-1, IPW-2, IPW-3, IPW-4]</td><td>4 Well Locations

Vertical (ft. SSTVD):
IPW-1: ~6,167</td><td>*Quarterly for first year, **annually thereafter</td></tr>
</table>

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
	Physical Monitoring: Downhole P Gauges		IPW-2: ~5,355 IPW-3: ~5,520 IPW-4: ~5,119	Continuous
*Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection **Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.				

E.2. Analytical Parameters

Fluid samples collected from units above the confining zone will be analyzed for geochemical parameters listed in **Table 9**. Acquired groundwater monitoring data will be periodically evaluated throughout the injection phase, and if listed parameters are determined to have a non-significant impact on meeting project monitoring objectives, they will be removed from the groundwater geochemistry analysis strategy. Shallow groundwater observation wells will be analyzed for groundwater geochemistry during baseline testing and monitoring. These wells will not be sampled and analyzed during the injection phase but may be used to provide additional evidence for groundwater protection should the operator or UIC Program Director deem it necessary.

Table 9: Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Shallow Groundwater (Chicot Freshwater Aquifer)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B (U.S. EPA, 2014a) or EPA Method 200.8 (U.S. EPA, 1994a)
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-AES / ICP-OES, EPA Method 6010D (U.S. EPA, 2014b) or EPA Method 200.7 (U.S. EPA, 1994b)
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16 (ASTM, 2016) Gravimetry, APHA 2540C (APHA) Oscillating body method APHA 2320B (APHA, 1997) EPA 150.1 (U.S. EPA, 1982) APHA 2510 (APHA, 1992) Thermocouple
USDW (Evangeline freshwater Aquifer), Above-Zone (Lower Miocene 1), and In-Zone (Frio) Observation Wells	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B (U.S. EPA, 2014) or EPA Method 200.8 (U.S. EPA, 1994)

Parameters	Analytical Methods
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D (U.S. EPA, 2014) (U.S. EPA, 2014) or EPA Method 200.7 (U.S. EPA, 1994)
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0 (U.S. EPA, 1993)
Isotopes: δ^{13} C of DIC	Isotope ratio mass spectrometry
Dissolved **CO_2** Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16 (ASTM, 2016) Gravimetry, APHA 2540C (APHA) Oscillating body method APHA 2320B (APHA, 1997) EPA 150.1 (U.S. EPA, 1982) APHA 2510 (APHA, 1992) Thermocouple

E.3. Sampling Methods

Groundwater sampling, sample preservation, and quality assurance will be conducted in accordance with methods/procedures described in **Section B** of the **QASP**.

E.4. Laboratory to be Used/Chain of Custody Procedures

Sample handling and chain of custody will be conducted in accordance with procedures described in **Section B** of the **QASP**.

F. Mechanical Integrity

Pineywoods CCS, LLC is committed to maintaining injection well mechanical integrity throughout the lifetime of the project. A well has mechanical integrity if:

- There is no internal leak in the casing, tubing, or packer;
- There is no significant external fluid movement out of the sequestration zone through channels adjacent to the wellbore; and
- Corrosion monitoring, pursuant to Subsection 40 CFR 146.90(c), reveals no loss of mass or thickness that may indicate the deterioration of well components (casing, tubing, or packer).

Pineywoods CCS, LLC will demonstrate internal and external mechanical integrity prior to injection (40 CFR 146.87), during the injection phase (40 CFR 146.89; 146.90), and prior to well plugging after injection has ceased (40 CFR 146.92). For more information on testing details and locations prior to injection, please refer to **Section A.3** of this plan and the **Pre-Operational Testing Plan**.

Internal mechanical integrity will be demonstrated with an initial annulus pressure test along with continuous tubing and annulus monitoring. External mechanical integrity will be demonstrated with DTS fiber optic cables in all injection and in-zone observation wells. More details on these methods and their frequencies are discussed in subsequent subsections and in the **QASP**.

Prior to injection, internal mechanical integrity will be demonstrated with an initial annulus pressure test (40 CFR 146.87(a)(4)). Following this initial pressure test and during the injection phase, Pineywoods CCS, LLC will demonstrate internal mechanical integrity in all injection wells by continuously monitoring the injection tubing and annular space pursuant to 40 CFR 146.88, 146.89, and 146.90. External mechanical integrity will be demonstrated with DTS fiber optic cables in all injection and in-zone observation wells. DTS fiber optic cables allow for continuous monitoring and will demonstrate external mechanical integrity prior to injection (40 CFR 146.87), during the injection phase (40 CFR 146.89; 146.90), and prior to well plugging after injection has ceased (40 CFR 146.92). **Table 10** summarizes internal and external MIT methods, locations, and frequency. For more information on testing details and locations prior to injection, refer to **Section A.3**of this plan and the **Pre-Operational Testing Plan**. If the DTS fiber optic cables fail, other methods listed in **Table 3** will be used to demonstrate external mechanical integrity.

Pineywoods CCS, LLC will comply with notification and reporting requirements described in **Section A.6** above.

MIT gauges and meters will be calibrated according to the manufacturer's specifications. Should loss of mechanical integrity be demonstrated through monitoring, Pineywoods CCS, LLC will take all steps necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is substantial endangerment to public health or the environment from any fluid movement out of the intended storage complex, Pineywoods CCS, LLC will implement the **Emergency and Remedial Response Plan (EERP)** (40 CFR 146.94), follow reporting requirements of 40 CFR 146.91, and restore and demonstrate mechanical integrity prior to resuming injection or plugging of the well. In the case of unscheduled or remedial well activity, the UIC Program Director will receive a remediation plan that includes a MIT activity to demonstrate well integrity following intervention per the **ERRP** (40 CFR 146.94).

If the well loses mechanical integrity prior to the next scheduled test date, then the well will be repaired and retested within 30 days of losing mechanical integrity. If the well loses mechanical integrity prior to the next scheduled test date, and is repaired, Pineywoods CCS, LLC will, in the next quarterly report, document the type of failure, the cause, the required repairs, and run a new test of mechanical integrity pursuant to 40 CFR 146.89.

F.1. Testing Location, and Frequency

Prior to injection, internal mechanical integrity will be demonstrated with an initial annulus pressure test (40 CFR 146.87(a)(4)). Following this initial pressure test and during the injection phase, Pineywoods CCS, LLC will demonstrate internal mechanical integrity in all injection wells by continuously monitoring the injection tubing and annular space pursuant to 40 CFR 146.88, 146.89, and 146.90. External mechanical integrity will be demonstrated with DTS fiber optic cables in all injection and in-zone observation wells. DTS fiber optic cables allow for continuous monitoring and will demonstrate external mechanical integrity prior to injection (40 CFR 146.87), during the injection phase (40 CFR 146.89; 146.90), and prior to well plugging after injection has ceased (40 CFR 146.92). **Table 10** summarizes internal and external MIT methods, locations, and frequency. For more information on testing details and locations prior to injection, refer to **Section A.3** of this plan and the **Pre-Operational Testing Plan**. If the DTS fiber optic cables fail, other methods listed in **Table 3** will be used to demonstrate external mechanical integrity.

Table 10. Mechanical integrity testing (MIT) location and frequency.

Monitoring Category	Monitoring Method	Frequency	Location
Internal MIT	1) Annulus Pressure Test 2) Annulus Pressure Monitoring	1) Prior to Injection 2) Continuous	PW (1-4)
External MIT	DTS	Continuous	Depths: *Surface to TD* PW (1-4) IPW (1-4)

F.2. Testing details

Internal mechanical integrity will first be demonstrated through an initial annulus pressure test (40 CFR 146.87). This test will include pressurizing the annulus to a specified level and observing its pressure for an established period of time (EPA 2013). A loss of mechanical integrity can then be detected by a loss of pressure which indicates the annular space is not sealed and is communicating with the tubing; loss of mechanical integrity, or a failed test, is one where there is a pressure loss of 10% or more within a 30-minute test period. The initial annulus test parameters such as this pass/fail criteria, test pressure, and duration will be designed pursuant to 16 TAC 3.9(12). This test is also discussed in section **E Mechanical Integrity Testing** of the **Pre-Operational Testing Plan.** Following the initial annulus pressure test, injection pressure, rate, and volume along with annulus pressure and volume will be continuously monitored throughout the injection phase and prior to well plugging to demonstrate internal mechanical integrity pursuant to 40 CFR 146.88, 146.89, 146.90, and 146.92. Specific details for continuous monitoring of the CO_2 stream and annulus are discussed earlier in **Section D** and **Section C.2**, respectively.

External mechanical integrity will be demonstrated with DTS fiber optic cables that run throughout each injection and in-zone observation well. External mechanical integrity tests are designed to detect fluids that have escaped from the wellbore and could migrate into USDWs (EPA 2013)[23]. The DTS fiber optic cables deployed in each well are capable of detecting fluid movement along channels adjacent to the wellbore in real-time by continuously monitoring the temperature from surface to total depth. Prior to injection, a temperature baseline profile will be recorded to identify injection phase temperature anomalies indicative of fluid flow beyond and leaks into the casing. These continuous DTS fiber optic measurements can therefore demonstrate external mechanical integrity[23] and replace the need for yearly temperature logging while satisfying 40 CFR 146.87, 146.88, 146.89, 146.90, and 146.92.

Both wellhead and downhole pressure gauges will meet or exceed ASME B 40.1 Class 2A (ASME, 2013) (0.5% accuracy across full range). Wellhead and downhole gauge specifications are described in detail in the **QASP**.

G. Pressure Fall-Off Testing

Pineywoods CCS, LLC will perform pressure fall-off testing of the injection wells pursuant to 40 CFR 146.90(f) and will use the EPA Region 6 *UIC Pressure Falloff Testing Guideline, Third Revision* (U.S. EPA, 2002). Pressure fall-off tests are designed to determine if reservoir pressures are tracking predicted pressures and modeling inputs. The results of pressure fall-off tests will confirm site characterization information, inform AOR reevaluations, and verify that projects are operating properly, and the injection zone is responding as predicted.

G.1. Testing Location and Frequency

The minimum frequency at which Pineywoods CCS, LLC will perform pressure fall-off testing is as follows:

- Prior to injection (baseline); and
- Three years from the start of injection and every five years thereafter until well plugging and abandonment.

Pressure fall-off tests will be conducted during periodic well workovers, or at a minimum three years after injection and once every five years thereafter, to calculate the changes in reservoir injectivity.

Table 11: Injection phase pressure fall-off testing frequency and schedule.

Monitoring Method	Frequency	Location
Pressure fall-off testing	1 prior to injection, 1 three years from the start of injection, and 1 every five years thereafter until well abandonment	PW (1-4)

G.2. Testing Details

A pressure fall-off test includes a period of injection followed by a period of no-injection or shut-in. Normal injection using the hub's CO_2 stream will be used during the injection period preceding the shut-in portion of the fall-off tests. This injection period will consist of, at a minimum, one week of continuous injection; however, several months of injection prior to the fall-off test will be part of the pre-shut-in injection period and subsequent analysis. The average injection rate is estimated to be 3,425 t/d per well (equivalent to 1.25 million MMt/y per well). Prior to the fall-off test this rate will be maintained. If this rate causes substantial changes in bottomhole pressure, the rate may be decreased. Injection rates on a well-by-well basis will be continuously recorded and employed in the analysis of the continuously recorded subsurface pressure data. Following the injection period, Pineywoods CCS, LLC and/or a third-party vendor will shut-in each well at the wellhead instantaneously in coordination with the injection compression facility operators. The shut-in period of the fall-off test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Pineywoods CCS, LLC will comply with notification and reporting requirements described in **Section A.6** above, reporting pressure fall-off data and interpretation of the reservoir ambient pressure following the test.

All data will be measured using permanent downhole pressure gauges, along with wellhead sensors, so testing durations can be determined in real-time. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at intervals of five seconds or less for the duration of the test. Both wellhead and downhole pressure gauges will meet or exceed ASME B 40.1 Class 2A (ASME, 2013) (0.5% accuracy across full range). The wellhead pressure gauge range will be 0-15,000 psi. The downhole gauge range will be 200-10,000 psi for pressure and 77 to 302 °F for temperature. Wellhead and downhole gauge specifications are described in detail in the **QASP**.

H. Carbon Dioxide Plume and Pressure Front Tracking

Pineywoods CCS, LLC. will implement indirect methods (**Table 12**) to track the CO_2 plume evolution and direct methods (**Table 13**) to track the pressure front propagation at specified locations and frequencies, per 40 CFR 146.90(g). This plan is designed to monitor the free-phase CO_2 plume location, thickness, and saturation; track the pressure development within the storage complex over time; validate computational modeling results; and demonstrate that operations are not leading to reservoir CO_2 or brine containment risks.

DTS technology will be run on the outside of the long string casing along the entirety of the wellbore and will record temperature measurements that can reveal the vertical location of near wellbore CO_2. This indirect CO_2 monitoring technology will be installed during well construction and will operate continuously during the baseline, injection, and post-injection periods. In practice, DTS systems typically provide temperature measurements at 1-meter (m) spacing along the entire cable. PNC wireline tools will be run to monitor the vertical saturations and profile of CO_2 within formations of interest.

Repeat 3D DAS VSP seismic surveys will be acquired from all wells with installed DAS fiber-optic cables to track CO_2 plume migration and prove containment within the reservoir. The typical resolution limit of surface seismic is five percent saturation, though with 3D DAS VSP, that saturation detection level can decrease depending on local geology. DAS technology used for the Pineywoods CCS Hub will be iDAS™ technology developed by Silixa or equivalent. 3D DAS VSP feasibility studies will be conducted once well locations are final to determine the resolution and surface source locations. In the unlikely event that 3D DAS VSP cannot image the plume with sufficient resolution, other indirect seismic technologies will be used. Indirect geophysical plume imaging (3D DAS VSP or other) will be acquired once before injection, three years after injection begins, and every five years thereafter during the injection period, as well as before the plugging and abandonment of any injection well.

Direct pressure monitoring will be implemented to track the pressure front evolution throughout the project's life using permanent downhole and surface pressure gauges. Gauges ported in the reservoir will record reservoir pressures and allow for better pressure front modeling. Pressure gauges ported to monitor the first permeable zone or lowermost USDW will allow Pineywoods

CCS, LLC to monitor any anomalous pressure changes above the primary caprock for early detection of containment loss.

Monitoring locations relative to the predicted location of the CO_2 plume within the AOR at five and ten-year intervals throughout the injection phase are shown in **Figure 6.** Two types of pressure front and CO_2 plume monitoring will occur at the Pineywoods CCS Hub: 1) plume imaging within the reservoir, and 2) containment confirmation above the primary caprock. Direct pressure measurements will be implemented for pressure front tracking, and indirect methods will be employed to track the CO_2 plume migration.

H.1. CO_2 Plume Monitoring Location and Frequency

As summarized in **Table 12** below, Pineywoods CCS, LLC will utilize a combination of indirect methods to detect, track, and monitor the CO_2 plume during the injection phase such as DTS, PNC logging, and repeat 3D DAS VSP. Locations of the observation wells with respect to the plume extents throughout the project are represented in **Figure 6**. Locations are subject to change based on final land access agreements and results of the repeat 3D DAS VSP seismic feasibility analysis.

DTS will be installed in all injection wells (PW-1, PW-2, PW-3, PW-4) and in-zone observation wells (IPW-1, IPW-2, IPW-3, IPW-4) and will continuously monitor temperature changes along the injection wellbore to detect intervals within the reservoir taking CO_2 and to detect any potential CO_2 breakthrough at in-zone observation wells. Repeat PNC logging will be run in all injection wells three years after injection begins, every five years thereafter during the injection period, and before the plugging and abandonment of any injection well or AOR re-evaluation. For the in-zone, above-zone (AOB-1, AOB-2, AOB-3), and deep observation wells (UOB-1, UOB-2, UOB-3, UOB-4, UOB-6), repeat PNC logging will only occur if containment loss is detected and will then be used as a containment verification technology. DAS fiber optic cable will be installed in all injection wells and in-zone observation wells.

H.2. CO_2 Plume Monitoring Details

The three technologies mentioned above will allow Pineywoods CCS, LLC to monitor the CO_2 plume evolution within the reservoir and provide evidence for its containment. At the injection wells, DTS data will help reveal high injectivity intervals within the reservoir zone taking fluid. At the in-zone observation wells, the DTS data will allow for detection of CO_2 breakthrough. PNC logging at injection wells will also reveal intervals with higher injectivity as well as provide quantitative measurements of CO_2 saturation within those intervals. PNC logging will only occur in the injection wells, in any in-zone observation well with CO_2 breakthrough, or any above-zone/deep observation wells with detected containment loss. DAS fiber optics will allow Pineywoods CCS, LLC to image the CO_2 plume in 3D within the reservoir as well as image the CO_2 plume should it migrate out-of-zone. Data from these technologies will be used to update reservoir models for more accurate CO_2 plume migration predictions.

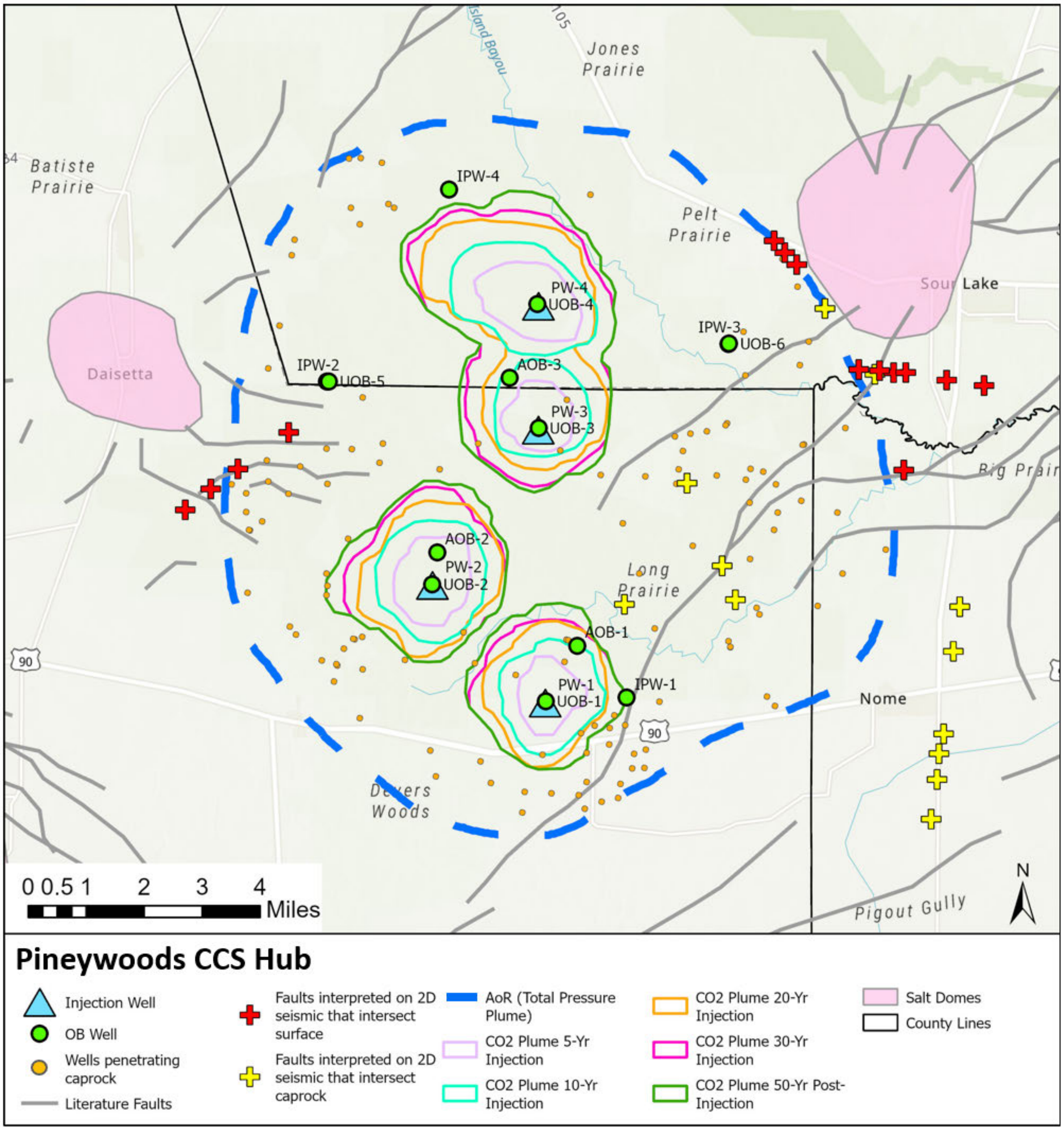

Figure 6: Pineywoods CCS Hub CO_2 plume evolution map.

Table 12: CO_2 plume injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
INDIRECT PLUME MONITORING			
Lower Frio	DTS	PW (1-4) IPW (1-4)	Continuous
	PNC[1]	PW (1-4)	Three years after injection begins, and every five years thereafter during the injection period
	1) 3D DAS VSP *OR* 2) Seismic	1) PW (1-4) & IPW (1-4) *OR* 2) Other seismic	

[1]PNC logging will only occur in wells with detected CO_2 breakthrough and containment loss.

H.3. Pressure Front Monitoring Location and Frequency

Pineywoods CCS, LLC will use permanent electronic downhole pressure gauges (Baker Hughes SureSENS QPT gauge or equivalent) placed above the packer and ported through to monitor each well's respective monitoring zone (see **Table 1**) pressures continuously. Wellhead pressure gauges will be installed as a backup pressure measurement should the downhole gauges fail. Downhole and surface pressure gauges will be installed in all injection wells and in-zone, above-zone, and deep observation wells (Table 13).

H.4. Pressure Front Monitoring Details

Pineywoods CCS, LLC will directly monitor the presence of the elevated pressure front by deploying electronic downhole pressure gauges (Baker Hughes SureSENS QPT gauge or similar) within every completion zone within injection wells, in-zone, above-zone, and deep observation wells. Injection and in-zone observation wells will monitor the evolution of the CO_2 plume in the Lower Frio Formation reservoir during injection. Above-zone and deep observation wells will monitor for pressures and temperature changes indicating potential containment loss in the Lower Miocene Formation and Evangeline Aquifer, respectively. All downhole gauges will be comprised of a corrosion resistant chrome alloy and will continuously record formation pressure and temperature from fixed-point locations at a set sampling interval.

Table 13: Pressure-front injection phase monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PRESSURE-FRONT MONITORING				
Frio	Pressure Gauges	PW (1-4) & IPW (1-4)	Above the Packer - Ported to Upper Frio	Continuous
Lower Miocene 1		AOB (1-3)	Above Packer - Ported to Miocene 1	Continuous
Evangeline Aquifer		UOB (1-3)	Above Packer - Ported to Evangeline Aquifer	Continuous

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