SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

This section includes the proposed Testing and Monitoring plan for the Pecan Island Injection Wells No. 001 and No. 002. The plan includes robust testing and monitoring programs that satisfy the requirements of Statewide Order (SWO) 29-N-6 **§3625.A** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**]. This plan will start before the injection of CO_2 commences. Monitoring strategies are designed to ensure and verify protection of the Underground Sources of Drinking Water (USDWs). These strategies consider, but are not limited to, the injection-stream composition, wellhead conditions, bottomhole operating parameters, seismic imaging for plume evolution, well integrity, and the above-zone confinement conditions. The location and information for all new monitoring wells are included, as are the parameters to be measured at each location. An in-depth summary of plume-growth monitoring, using time-lapse seismic imaging technology, is presented. The monitoring activities described in this plan will be carried out during the entirety of the life of the injection wells, including the post-injection site care (PISC) phase. The monitoring activities will follow a predetermined timeline tailored toward verifying that the observed plume development is according to modeling expectations, as well as demonstrating that the injected CO_2 is not endangering a USDW.

5.2 Reporting Requirements

In compliance with SWO 29-N-6 **§3629.A** [40 CFR **§146.91**], ExxonMobil will provide routine reports to the Underground Injection Control (UIC) program director (UIC Director). The report contents and submittal frequencies are described below:

- Any noncompliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs
    - Verbal Notification – Reported within 24 hours of event
- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW
    - Verbal Notification – Reported within 24 hours of event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of event
- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
    - Written Notification – Reported within 72 hours of composition change
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event
- Description of any event that triggers a shut-off device either downhole or at the surface and the response taken
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 72 hours of event

Semiannual Reports:

Reports will include all contents and situations listed above, in addition to the following:

- Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure
- Monthly volume and/or mass of the CO_2 stream injected over the reporting period, and the volume injected cumulatively over the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring as described here, throughout *Section 5*

Reports to be submitted within 30 days after the following events:

- Any well workover
- Any test of the injection well conducted, if required by the UIC Director

Notification to the UIC Director, in writing, 30 days in advance of:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of an injection well

ExxonMobil will submit all reports, submittals, and notifications to both the EPA and the Louisiana Department of Natural Resources (LDNR) and ensure that all records are retained throughout the life of the project. In accordance with SWO 29-N-6 **§3629.A.4.c** [40 CFR **§146.91(f)**], records will be retained for a 10-year period after site closure. Additionally, injected-fluid data, including nature and composition, will also be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

In accordance with SWO 29-N-6 **§3625.A.10** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised as necessary, at a minimum of every 5 years to incorporate collected monitoring data. Plan amendments will also be submitted within 1 year of an area of review (AOR) reevaluation, following significant facility changes—such as the development of offset monitoring wells or newly-permitted injection wells within the AOR, or as the UIC Director requires.

5.4 Testing Strategies

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, ExxonMobil will conduct a step-rate injectivity test to measure the fracture gradient of Pecan Island Injection Wells No. 001 and No. 002 in compliance with SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and SWO 29-N-6 **§3617.B.5.c** [40 CFR **§146.87(e)(3)**]. The details of the step-rate test are provided in *Section 4.3.4*.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with SWO 29-N-6 **§3627.A.2** [40 CFR **§146.89(b)**], ExxonMobil will ensure the mechanical integrity of each injection well by performing annulus pressure tests after the well has been completed, prior to injection, and annually afterwards. This annular pressure test specifically verifies the integrity of the annulus between casing and tubing above the packer. During well construction, prior to completion, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure to verify its integrity. The annual pressure tests must be witnessed by an agent of the Louisiana Office of Conservation.

The annular pressure tests are designed to demonstrate mechanical integrity of the casing, tubing, and packer. These tests are conducted by pressuring the annulus to a minimum of 500 pounds per square inch (psi) surface pressure. A block valve is then used to isolate the test-pressure source from the test-pressure gauge upon test initiation, with all ports into the casing annulus closed except the one monitored by the test-pressure gauge. The test pressure will be monitored and recorded for a minimum duration of 30 minutes, using a pressure gauge with sensitivities that can indicate a loss of 5%. A lack of mechanical integrity is indicated by any loss of test pressure exceeding 5% during a minimum elapsed period of 30 minutes.

All annulus pressure test results will be submitted to the Injection and Mining Division (IMD) on Form UIC-5 within 30 days of completion.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. More details regarding continuous monitoring are described in *Section 5.5.1 and 5.5.2.*

5.4.3 External Mechanical Integrity Testing

Following the requirements of SWO 29-N-6 **§3627.A.3** [40 CFR **§146.89(c)**], ExxonMobil will perform an annual external mechanical integrity test (MIT). A noise log will be run to meet this requirement using the distributed acoustic sensing (DAS) interrogator and fiber cables installed in the well. The aim of this measurement is to detect the sound generated by the movement of fluid through a leak or channel behind the casing. One of the benefits of this approach is that measurements can be obtained while the well is operating, unlike an approach based exclusively on temperature measurements. One anticipated challenge of measuring noise during injection conditions is the competing noise from the injection stream. If the noise interference reduces the diagnostic power of the noise logs below acceptable levels, then the noise measurements will be repeated when the well is shut in.

[redacted]

[redacted]

As a contingency, ExxonMobil can revert to a determination using one or more of the following methods: a temperature log, data collected using DTS, a wireline, or an oxygen-activation log.

All logs recorded during the external MIT will be submitted to the UIC Director within 30 days of log-run completion.

5.4.4 Pressure Fall-Off Testing

The injection interval is several thousand feet thick and is partitioned into multiple injection stages [redacted]. Each injection stage is instrumented with multiple downhole pressure gauges. After the end of injection for a given stage, it will be plugged back to isolate that stage. The next injection stage [redacted].

ExxonMobil will perform a required pressure fall-off test at the end of every injection stage or every 5 years, whichever is more frequent, to meet the requirements of SWO 29-N-6 **§3625.A.6** [40 CFR **§146.90(f)**]. After an injection stage is permanently abandoned, the pressure gauges clamped to the tubing within each injection stage will measure the natural pressure decay after injection ceases in that stage. The objective of the pressure fall-off test would be automatically satisfied by the continued measurements in the abandoned zone. When a pressure fall-off test is conducted in an injection stage and injection continues in that stage after the test, the test procedure in *Section 5.4.4.1* would be followed. This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.4.1 Testing Method

The CO_2 injection rate and pressure will be held as constant as possible prior to the beginning of the fall-off test, and data will be continuously recorded during testing. After the well is shut in, continuous pressure measurements will be taken with a downhole pressure gauge array installed across each injection stage. This array consists of a tubing encapsulated conductor (TEC) cable equipped with pressure gauges. The fall-off period will end once the pressure-decay data plotted on a semi-log plot is a straight line, indicating radial-flow conditions have been reached.

5.4.4.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, and hydraulic property and boundary conditions, will be determined through standard diagnostic plotting. This determination is accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by comparing pressure fall-off tests performed prior to initial injection with later tests. The effects of two-phase flow effects will also be considered. These well parameters resulting from fall-off testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary.

All pressure fall-off test results will be submitted to the IMD within 30 days of test completion.

5.4.4.3 Quality Assurance/Quality Control

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results. Further validation of the test results will be justified by extended collection of pressure data from the plugged and abandoned injection stages. The continuation of pressure monitoring in deeper, inactive stages allows for recording of the naturally occurring pressure decay. Pressure communication between stages can be detected with this system.

5.4.5 Cement Evaluation and Casing Inspection Logs

A cement bond log will be run after the casing installation and the required cement-hardening time to understand the quality of the cement. [redacted]

[redacted]

- [redacted]
  [redacted].
- The UIC Director requests it.

[redacted] can be analyzed to identify and localize casing corrosion, addressing SWO 29-N-6 **§3627.A.4** [40 CFR **§146.89(d)**].

5.5 Monitoring Programs

5.5.1 Continuous Injection Stream Physical Monitoring

ExxonMobil will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with SWO 29-N-6 **§3625.A.2** [40 CFR **§146.90(b)**]. A Supervisory Control and Data Acquisition (SCADA) system facilitates the operational data collection and monitoring for the full sequestration site, consisting of the pipeline, the injection wells, and the above-zone monitoring interval (AZMI) monitoring wells.

The injected CO_2 stream pressure will be continuously monitored in the CO_2 piping near the pipeline-wellhead interface. The annulus pressure will also be continuously recorded at the wellhead. The injection interval is thousands of feet thick and is vertically partitioned into multiple injection stages. Each stage is several hundred feet thick and has continuous-recording downhole pressure and temperature gauges installed. Combined with the wellhead-pressure measurements, it is therefore possible to continuously characterize the injection stream in detail. This analysis can be further supplemented on demand by DTS and DAS measurements from the fiber optic cable on the tubing, using a permanently available interrogator of each type. If necessary, this enables more detailed flow characterization along the entire length of the well, including the pipeline between the wells and the central platform. At the central platform, there is a high-accuracy Coriolis flow meter to measure the mass flow rate in the pipeline that connects to the injection wells. Each of the injection wells also has its own Coriolis flow meter to quantify the partitioning of the flow between the two injectors.

5.5.1.1 Analytical Methods

ExxonMobil will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination of trends to help determine a need for equipment maintenance or calibration. Semiannual reports of the monitoring data will be submitted to the UIC Director.

5.5.2 Continuous Injection Stream Composition Monitoring

Under SWO 29-N-6 **§3625.A.1** [40 CFR **§146.90(a)**], ExxonMobil will determine the chemical composition of the injection stream with the objective of understanding potential interactions between CO_2 and other injectate components, as well as with the wellbore materials. This determination is accomplished by quarterly sampling of the injection stream and subsequent laboratory analysis.

5.5.2.1 Sampling Methods

The quarterly measurements are obtained by extracting samples from the injection stream at a location where the composition is representative for the injection well. The samples are subsequently sent to a laboratory for analysis.

5.5.2.2 Parameters Measured

Table 5-1 lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-1 – Injection Stream Measurements

Parameter/Analyte	Frequency	Method
Pressure	Continuous	Pressure gauges at wellhead (downstream of choke) and downhole
Temperature	Continuous	Temperature gauges at platform and downhole
pH	Quarterly	Lab analysis
Water (lb/mmscf*)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis
Hydrogen Sulfide (ppm**)	Quarterly	Lab analysis

*mmscf – million standard cubic feet

**ppm – parts per million

5.5.3 Corrosion Coupon Monitoring

Monitoring of corrosion to the well tubing and casing materials will be conducted in adherence to SWO 29-N-6 **§3625.A.3** [40 CFR **§146.90(c)**]. A quarterly evaluation of a corrosion coupon monitoring system, implemented by ExxonMobil, will be performed to meet this requirement. A corrosion coupon station or rack is provided as part of well-materials integrity monitoring. Multiple coupons will be exposed to the stream composition to provide ongoing evaluation of materials compatibility. Results will be reported to the UIC Director semiannually.

5.5.3.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and production casing, will be exposed to the conditions of the pipeline's CO_2 flow. The coupons will be removed on a quarterly schedule and examined for corrosion per American Society for Testing and Materials (ASTM) standards for corrosion testing evaluation. The coupons, once removed, will be visually inspected for signs of corrosion, including pitting, and measured for weight and size each time they are removed. The corrosion rate will be estimated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4 Fluid Quality Monitoring

Fluid samples will be taken periodically from the USDW and AZMI monitoring wells.

The USDW monitoring wells target the deepest USDW formation, and the initial sampling frequency is quarterly. This sampling frequency is for both the pre-injection phase and the first 3 years of injection. This quarterly sampling characterizes any potential seasonal fluctuation in this USDW. [redacted]

One example of these complementary leakage-detecting monitoring measurements is the deep fluid sampling provided by the AZMI monitoring wells. This type of well targets the first permeable formation above the UCZ. This formation is referred to as the AZMI. This interval is a deep formation [redacted] in which no seasonal variation is expected. Therefore, sampling this formation annually from the start of the project will provide sufficient resolution for analysis. The first (and therefore deepest) injection stage of the project is [redacted] deeper than the AZMI and is separated by multiple continuous shales.

Table 5-2 summarizes the parameters analyzed and the planned sampling frequency, which apply to all USDW and AZMI wells. Anomalous measurements will initiate further studies, including a more detailed analysis of existing data to understand the potential cause of the variation. This analysis could take the form of geochemical modeling and review of trends observed in samples collected from all wells prior to the anomalous measurement.

These studies could also include integration with other measurements, such as time-lapse seismic and AZMI pressure measurements, as described later in *Sections 5.5.8* and *5.5.6*, respectively. If this study does not satisfactorily rule out the leakage scenario, further contingency data acquisition will be considered. The options include acquiring another fluid sample to verify the original measurement, or complementary measurements, such as a repeat cased-hole wireline log in the injector—or AZMI monitoring wells to independently detect the presence of CO_2. Details of the USDW and AZMI sample-collection strategies are discussed in *Sections 5.5.5*. and *5.5.6*, respectively.

Table 5-2 – USDW and AZMI Monitoring Well Sampling Program During the Injection Phase

Parameter/Analyte	USDW Well Frequency	AZMI Well Frequency
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	[redacted] [redacted]	[redacted]
Gas composition (CO_2, CH_4, C_{2+}, O_2, N_2)		
Dissolved cations (i.e., Ba, Ca, Fe, Mg, Mn, Na, other relevant metals)		
Dissolved anions (i.e., HCO_3 Br, Cl, F, SO_4)		

Measurements are performed on gases collected from the fluid samples by depressurizing them to atmospheric conditions in a controlled laboratory environment.

5.5.4.1 Analytical Methods

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-2. If results indicate the existence of impurities in the injection stream, the diagnostic power of these constituents will be assessed to determine if they should be included in the analysis of the water samples. Testing results will be stored in an electronic database.

Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Change in total dissolved solids (TDS)
- Change in signature of major cations and anions
- Increase in carbon dioxide concentration
- Decrease in pH
- Increase in concentration of injectate impurities
- Increase in concentration of leached constituents

5.5.4.2 Laboratory to be Used/Chain of Custody Procedures

The analysis of the fluid samples will be submitted to the IMD through a state-approved laboratory. ExxonMobil will observe standard chain-of-custody procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

5.5.4.3 Quality Assurance and Surveillance Measures

ExxonMobil will collect replicate samples and sample blanks for quality assurance/quality control purposes. The samples will be used to validate test results, if needed.

5.5.4.4 Plan for Guaranteeing Access to All Monitoring Locations

Placement of the well locations is optimized to be accessible from roads or, for more remote locations, preexisting dredged channels.

5.5.5 USDW Monitoring Wells

To comply with SWO 29-N-6 **§3625.A.4** [40 CFR **§146.90(d)**], five USDW monitoring wells will be drilled into the deepest USDW sand to support the sequestration project. The deepest USDW formation is defined by salinity and is currently estimated to occur at a depth of approximately 850 ft at Pecan Island Injection Wells No. 001 and No. 002. When the injection wells and USDW monitoring wells are drilled, the USDW depth will be confirmed in each well through the collection of open-hole wireline-resistivity logs.

These five USDW monitoring wells surround the injection wells and provide USDW-quality verification for the sequestration project. Hydrological modeling predicts that USDW flow is toward the north to northwest, which is why three of the five USDW monitoring wells (Wells No. 003, No. 004, and No. 005) are placed in that direction. The remaining two USDW monitoring wells (Wells No. 001 and 002) are in the upstream direction (south to southeast). Water samples will be collected from the USDW monitoring wells to monitor for signs of CO_2 or brine leakage. Figure 5-1 (*Section 5.5.5.1*) displays the monitoring well locations, which are also listed in Table 5-3 (also in *Section 5.5.5.1*).

The USDW monitoring wells are positioned to maximize the value of the information collected, using knowledge of the local hydrology and subsurface features that could potentially act as leakage pathways. USDW Monitoring Wells No. 001 and No. 002 are north (*i.e*., downstream) of a noteworthy surface-going fault plane. These monitoring wells are therefore optimally positioned to detect any change in fluid chemistry caused by movement of either CO_2 or formation brines along the fault into the USDW. Reservoir simulations predict that CO_2 will never get close to this fault plane, and time-lapse seismic will provide valuable information to validate the model prediction. USDW Monitoring Wells No. 001 and No. 002 serve as early detection in the event of unanticipated CO_2 leakage along the fault. Simulation models also predict that the pressures at the fault plane do not increase to levels that would allow brines to be pushed up along the fault and into the USDW, but these two wells would verify these predictions.

In addition to being downstream of the USDW hydrology, Monitoring Wells No. 003, No. 004, and No. 005 are also in the preferential growth direction (*i.e.*, updip) of the injected CO_2. These monitoring wells are therefore more likely to encounter CO_2 or its effects on the USDW chemistry if a leak does occur. USDW Monitoring Well No. 003 is also adjacent to a legacy oil-and-gas wellbore. While this legacy wellbore will be remediated to minimize any potential leak through the confining zone, a nearby USDW measurement from Monitoring Well No. 003 will provide extra certainty. AZMI Monitoring Well No. 001 further reduces the likelihood of undetected leakage through the adjacent legacy wellbore. This reduced risk is accomplished by including the legacy wellbore in the cone-shaped area of the subsurface that can be monitored with the DAS time-lapse seismic-monitoring methodology, as described in *Section 5.5.8*. USDW Monitoring Well No. 004 is also downstream of two oil-and-gas legacy wells in the vicinity of Injection Well No. 002. While both wells will be remediated to minimize the risk of leaks through the confining zone, this well will provide further verification. While USDW Monitoring Well No. 005 is the farthest away from the injection well—and therefore the least likely to see the effects of any leak during the life of the project—it is also the well downstream to most legacy wellbores and therefore able to detect most potential leakage signatures.

5.5.5.1 Fluid Sampling Methods

Water samples will be collected from the USDW monitoring wells at the surface. Two well volumes will be purged to collect a pristine sample that represents the USDW water rather than water that has resided for a significant time in the wellbore. These water samples will be analyzed in the field for a variety of physical parameters, including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity, as these parameters are sensitive to alteration over time. Additional analyses include TDS, concentrations of cations, anions, CO_2, and CH_4. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

The fluid-sampling parameters and frequencies for the groundwater monitoring wells are shown in Table 5-2. Details regarding sampling techniques and processes are explained in *Section 5.5.4*.

[redacted]

Figure 5-1 – Location of USDW Monitoring Wells Surrounding the Two Injection Wells

Table 5-3 – USDW Monitoring Well Details

Monitoring Well Location Info	USDW Monitoring Well No. 001	USDW Monitoring Well No. 002	USDW Monitoring Well No. 003	USDW Monitoring Well No. 004	USDW Monitoring Well No. 005
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A detailed wellbore schematic for USDW Monitoring Well No. 001 is shown in Figure 5-2 as a representative example of such wells. Wellbore schematics of USDW Monitoring Wells No. 001 through No. 005 are provided in *Appendix F*.

[redacted]

Figure 5-2 – USDW Monitoring Well No. 001 Schematic

5.5.6 AZMI monitoring wells

Two monitoring wells will be drilled to a depth corresponding to the first permeable formation above the UCZ, which is referred to as AZMI. These two wells monitor both injection wells in this project. Each well is directly updip from one of the project's two injection wells. These monitoring wells are located on ExxonMobil Low Carbon Solutions Onshore Storage LLC's property as shown in Figure 5-3, with the location details provided in Table 5-4.

[redacted]

Figure 5-3 – Pecan Island Project AZMI Monitoring Wells and the Two Injection Wells

Table 5-4 – AZMI Monitoring Well Location Details

Monitoring Well Location Info	AZMI Monitoring Well No. 001	AZMI Monitoring Well No. 002
NAD83 (2011) Latitude	[redacted]	[redacted]
NAD83 (2011) Longitude	[redacted]	[redacted]
NAD27 Easting	[redacted]	[redacted]
NAD27 Northing	[redacted]	[redacted]

Datum	[redacted]	[redacted]
Total Depth	[redacted]	[redacted]
Type	[redacted]	[redacted]

5.5.6.1 Fluid Sampling Methods

[redacted] The residual fluid will be analyzed for the physical parameter and geochemical species provided in Table 5-2. Sample collection will occur before the start of injection, to characterize the original chemical composition of the formation fluids. As discussed in *Section 5.5.4*, unexpected changes in the fluid chemistry in the AZMI may be caused by a leakage or other processes and would result in further studies to determine if a leak is present.

5.5.6.2 Pressure Monitoring

Although not required by Class VI regulations, ExxonMobil will continuously monitor the pressure of the first permeable formation identified above the UCZ in the AZMI monitoring wells using a downhole pressure gauge. Deviations from baseline pressures after the start of injection will initiate further review in the area. This review includes a study to rule out sensor drift, and a comparison to the pressure trend observed prior to injection. This comparison would provide insights into potential far-field activities in the same zone. Furthermore, pressure increase in the injection interval causes those sands to physically expand, which may compress the overlying formations and increase pore-fluid pressure without any leakage path being present. This benign effect would also be modeled and compared against observations to further assess the likelihood of the pressure response indicating leakage.

5.5.6.3 Seismic Imaging

A fiber optic cable will be cemented in the annulus of the long casing string. The fiber optic cable gives ExxonMobil the ability to use DAS with time-lapse vertical seismic profile (VSP) surveys to detect CO_2 in the injection sands below the confining zone, as well as any CO_2 that has leaked upward in the vicinity of the wellbore. These time-lapse DAS-VSP surveys are also sensitive to changes in pore pressure, but this effect is anticipated to be minor compared to the sensitivity to changes in CO_2 saturation. A baseline survey will be established at each injection well and AZMI monitoring well for future survey reference and plume tracking. Further details of the seismic program are discussed in *Section 5.5.8*.

A detailed wellbore schematic for AZMI Monitoring Well No. 001 is shown in Figure 5-3 as a representative example of both AZMI monitoring wells. Wellbore schematics of AZMI Monitoring Wells No. 001 and No. 002 are displayed in *Appendix F*.

[redacted]

Figure 5-4 – AZMI Monitoring Well No. 001 Schematic.

5.5.7 Injection Interval Monitoring

The injection interval will be monitored through measurements taken from the injection wells themselves. Each well will continuously monitor pressure and temperature in all injection stages of the injection interval, including previously injected-into stages. These stages will continue to be monitored for the life of the well.

This project includes two injection wells targeting the same sand formations. The pressure measurements taken from the two wells will allow the wells to monitor each other within the injection interval. The fiber optic cables installed in the injection and AZMI monitoring wells facilitate time-lapse seismic imaging of the CO_2 plume in the injection sands with the VSP geometry. These time-lapse seismic images are also capable of detecting potential leakage into the overburden and are described in more detail in *Section 5.5.8.*

5.5.8 Injection Plume Monitoring

ExxonMobil proposes a two-tiered system for plume and pressure-front tracking per the operational monitoring requirements of SWO 29-N-6 **§3625.A.7** [40 CFR **§146.90(g)**]. Plume calculations based on continuously recorded pressures and temperatures will be used as a direct monitoring approach. The fiber optic cables in the injection and monitoring wells will be used as recording devices to indirectly monitor the plume with time-lapse seismic imaging, using the DAS-VSP acquisition geometry.

- <u>Direct method, targeting injection zone pressure</u>: Using the multiple downhole pressure gauges installed in both injection wells.

- <u>Indirect method, targeting CO_2 presence</u>: Using DAS-VSP surveys.

This two-tiered system will serve two purposes: first, to verify reservoir conditions during injection; and second, to track plume migration and validate the plume model. Continuous pressure and temperature monitoring of the injection reservoir will allow for continuous monitoring of the reservoir conditions and calculations. The actual plume migration will be determined by VSP surveying. The VSP will be run prior to injection initiation and periodically as needed, with a detailed discussion of timing in *Section 5.5.8.2.*

5.5.8.1 <u>Direct Monitoring: Pressure</u>

The two injection wells are instrumented with many downhole pressure gauges to continuously monitor the pressure in the multiple injection sands. The pressure response recorded by any gauge would not only be a representation of the injection through that well, but would also be affected by the far-field pressure response from the other injection well. This response effectively empowers one injection well to function as the in-zone pressure monitoring well of the other. These recorded time series provide insight into the reservoir connectivity between the two injectors. These measurements are sufficient for pressure monitoring when both injection wells inject in the same sands of an injection stage, and also in those occasions when the injectors may target separate injection stages. In the latter case, the absence of simultaneous injection in a stage means that the recorded pressure response is exclusively the far-field pressure response of the other injector. This case corresponds to the most conventional understanding of a pressure-monitoring well.

The reservoir model built during the site-evaluation phase may be used to predictively monitor the reservoir conditions during injection operations. Continual monitoring of bottomhole pressures and temperatures, combined with known reservoir parameters, will be used to derive reservoir conditions throughout the injection stages. In addition to the bottomhole measurements from this injection well, the second injection well will collect relevant data to assist with tracking plume development. The two wells will work in conjunction with each other to monitor both plumes.

Any periods of shut-in of the well can be observed and treated as a fall-off test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continual measurements obtained during regular operating conditions, will aid in updating models and forecasts.

5.5.8.2 Indirect Monitoring: Vertical Seismic Profile

ExxonMobil will use a time-lapse VSP as the first method to monitor the CO_2 plume extent and development to meet the operation monitoring requirements specified in SWO 29-N-6 **§3625.A.7.b** [40 CFR **§146.90(g)(2)**]. A VSP is a seismic survey where the seismic sources are spaced out over the surface of the earth, with the recording devices placed in the wellbore. Like previous exploration seismic surveys that cover the acreage, the seismic sources are explosive charges buried at sufficient depth to ensure good coupling of the acoustic energy with the subsurface and to avoid environmental damage. These sound waves travel through the subsurface and partially reflect whenever they encounter contrasts in acoustic properties, in a process very similar to echoes observed from the acoustic contrast between the air and a wall. Through this dependence on acoustic properties, these reflected sound waves contain information about the structure of the subsurface, including the fluid properties.

The recording devices in a VSP survey are placed on fiber optic cables in the well, using DAS technology. From a functional perspective, DAS converts the entire fiber optic cable into an array of microphones closely spaced (in tens of feet) that can capture the sound waves along the length of the well from the seismic sources. These recordings can then be used to form an image of the subsurface around the wellbore. Figure 5-5 illustrates the concept of a DAS-VSP.

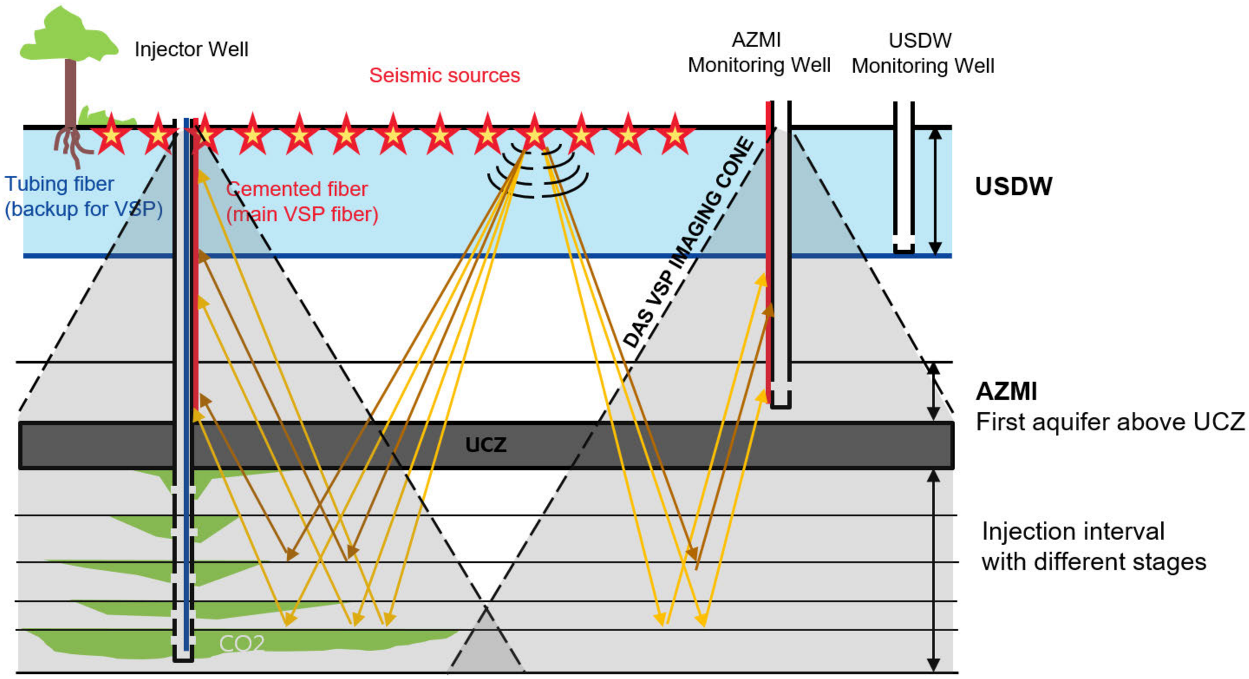

Figure 5-5 – Illustration of a DAS Vertical Seismic Profile

In Figure 5-5, the stars represent the buried seismic sources, and the red line along the injector and AZMI monitoring wells is the primary imaging fiber cemented up to the UCZ. An additional fiber, represented by the blue line, is installed on the injector tubing and is also capable of recording the same seismic waves, although likely with higher noise. One seismic source is highlighted. The energy traveling out from this source reflects on all acoustic contrasts (*e.g.*, layers) in the earth, with two layers highlighted using sets of orange arrows.

It is possible to acquire DAS-VSP multiple times during the life of the project, a process known as time-lapse DAS-VSP. The seismic waves are sensitive to the fluid in the pores of the rock. When CO_2 replaces the original formation brines, it changes the acoustic impedance of the rock, which in turn changes the amplitude of the reflection in the repeat survey. The seismic velocity of the rock is also impacted. The seismic waves traveling through the CO_2 will be delayed compared to earlier seismic surveys, where the rocks were still filled with brine. By comparing the changes in amplitude and delays in arrival time between the repeated seismic surveys, it is possible to trace in 3D where the CO_2 plume is, in a cone-shaped volume around the wellbores.

ExxonMobil performed time-lapse seismic modeling, using logs from offset wellbores, to estimate the magnitude of the time-lapse seismic response due to CO_2 replacing brine. The modeled response is significant, which is consistent with expectations for the level of consolidation in these sands. In addition, the seismic rock properties are also sensitive to changes in pore pressure due to injection. This time-lapse seismic methodology has a decades-long track record for oil-and-gas exploration, and the DAS-VSP configuration is a subset of this. That configuration has seen a significant uptick in usage in the last decade, with improvement in fiber optic sensing technology.

ExxonMobil proposes the following DAS-VSP monitoring schedule:

- The first baseline DAS-VSP survey is acquired prior to injection, because the seismic recordings represent a well-understood initial state of the subsurface fluids (*i.e.*, brine filled).

- [redacted]

- [redacted] Survey timing may be more frequent, depending upon the currently undetermined moment of transition of one injection stage to the next. The objective of earlier surveys is predominantly to establish conformance to reservoir models. Containment risk is limited, especially in the early phase of the project, because the injection stages are still much deeper than the UCZ—and there are multiple baffles/seals below the UCZ that would impede any unexpected upwards migration of CO_2. The timing of these monitor surveys will be refined in future updates of the monitoring plan according to 40 CFR **§146.90(j)**.

- [redacted]

[redacted] cemented fiber optic cables are expected to provide data of the highest quality, because of (1) cement providing better coupling to the formation, (2) fewer external casing strings distorting the seismic waves, and (3) partial shielding from the noise of CO_2 flowing through tubing. In addition, the quality of the seismic data recorded by the tubing fiber is analyzed in the first two surveys to understand if the increased recording depth provides imaging uplift. If not, then these tubing-fiber recordings will be dropped in following surveys. Regardless, the expectation is that DAS and DTS recordings on this tubing fiber will be useful for external MIT (described in *Section 4.4.3*) and injection-flow profiling.

Table 5-5 – Fiber Cable Arrays Used in DAS-VSP

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

- [redacted]

[redacted]

- [redacted]

- [redacted]

- [redacted]

Figure 5-6 shows the acquisition design and modeling details for the baseline (left column) and monitor (right column) surveys. The pre-injection baseline survey is important, because it represents a known subsurface saturation state (*i.e.*, brine), and monitor surveys can therefore be compared against it to determine the extent of the CO_2 plume. This baseline survey is very conservative and contains source points that may not be necessary for adequate imaging of the plume (Figure 5-6(a)). Examples of why some of these baseline source points may not contribute to the time-lapse monitoring are (1) the seismic-wave reflection angle potentially being larger than desirable for plume imaging for the faraway sources, and (2) the plume potentially not migrating far enough during the life of the project to require imaging with those source points. Including these sources in the pre-injection baseline maximizes both flexibility and the ability to meet the indirect plume-monitoring objectives of 40 CFR **§146.90 (g)(2)**.

[redacted]

Figure 5-6(f) shows that, at these depths, the imaging cones of the two injectors and two monitoring wells merge and provide almost continuous coverage. This placement includes significant coverage toward the north, the direction where the plume is expected to preferentially move due to subsurface dip. Even the shallowest injection stage, reached at the end of the project, is expected to have seismic imaging coverage of [redacted]

[redacted] away from the wellbore, as Figure 5-6(d) shows. Outside of this black circle, the fold rapidly decreases, and the range of seismic reflection angles usable for imaging becomes limited. While it may still be possible to form a time-lapse image beyond this black circle, noise will become limiting at a wellbore distance that depends on factors such as the repeatability of the seismic survey.

In addition to indirect monitoring of the movement of the CO_2 in the injection stages, the DAS-VSP is also sensitive to any potential leaks through the UCZ. This further increases the safety of the storage operation.

[redacted]

[redacted]

[redacted]

Figure 5-6 – DAS-VSP Program Details

5.5.9 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy SWO 29-N-6 **§3625.A** [40 CFR **§146.90**]. Reporting and reevaluation requirements will be executed by ExxonMobil for the life of the project, including post-injection. Monitoring strategies are included for the injection stream composition and wellhead CO_2 conditions using pressure and temperature gauges, as well as mass flowmeters, to allow for continuous reading of data. Bottomhole operating parameters are monitored by the pressure gauges array that extend the full length of the injection interval. Well integrity is confirmed by the execution of annual tests. Above-zone confinement is monitored by multiple new wells equipped with pressure sensors and periodic fluid sampling. USDW safety is ensured by monitoring multiple groundwater wells that are distributed in a manner that allow for effective sampling of the bottomhole fluids. The appropriate well equipment and its related use is explained within the respective sub-sections of this application.

The individual injection stages of the injection wells are also instrumented with pressure and temperature gauges, which enable direct monitoring of the formation pressure. Furthermore, these pressure gauges verify the pressure decay toward pre-injection levels after injection in each stage is finished.

A significant part of the plan is the monitoring and tracking of the injected CO_2 in the subsurface. The fiber optic cables in both the injection wells and AZMI monitoring wells enable time-lapse DAS-VSP surveys, which are indirect measurements of changes in the injection formation. Such surveys are sensitive to both the presence of CO_2 and, to a lesser extent, the formation pressure. Even though the cemented fiber optic cables used for imaging terminate above the UCZ, modeling shows that imaging below the UCZ is viable.

Time-lapse DAS-VSP surveys have been used around the world for both oil and gas operations and CO_2 monitoring. For ExxonMobil, using offset petrophysical data modeling results has generated a modeled differential in compressional velocity and density likely to produce detectable changes in the reservoir, where the connate fluid has been replaced by carbon dioxide. [redacted].

This method eliminates the need for additional penetrations within the injection formations for monitoring purposes beyond what is proposed in this plan. This approach minimizes the risk of inadvertently forming a leakage path through the upper confining zone.

The contents of this plan will be carried out during the entirety of the life of the injection wells, including post-injection monitoring following a predetermined timeline, based on both updated plume growth and observed well conditions at the time of planned injection cessation.

Table 5-6 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-6 – Testing and Monitoring Plan Measurements

Equipment / Measurement	Regulation	Comment	Frequency
Coriolis flow meter	§3625.A.2 §146.90b	Measures mass flow rate	Continuously
Corrosion coupon	§3625.A.3 §146.90c	Measures corrosion levels on the types of metal used in the project	Quarterly
Injection stream sampling	§3625.A.1 §146.90a	Provides more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central platform temperature gauge	§3625.A.1 §146.90a	Measures temperature of the total injection stream at the platform before partitioning to both injectors	Continuously
Injector wellhead tubing P gauge	§3625.A.1 §146.90a	Measures downstream of choke	Continuously
Injector wellhead annulus P gauge	§3625.A.2 §146.90b	Verifies annulus pressure maintained	Continuously
Injector annulus pressure test	§3627.A.2 §146.89b	Verifies absence of leak in annulus	Annually
Injector downhole P&T gauges on sand screens of individual injection stages	§3625.A.2 §146.90b	Measures downhole pressure and temperature (P&T) as close as possible to formation (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	§3625.A.6 §146.90f	Measures fall-off of pressure after abandoning injection stage and initiating injection in next stage above	At the end of every injection stage or every 5 years, whichever is more frequent
	§3625.A.7.a §146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injectors, especially when injection intervals are staggered between wells	Continuously
[redacted]	[redacted]	[redacted]	[redacted]

		[redacted]	
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Injector casing-inspection log	§3625.A.5 §146.90e	[redacted]	[redacted]
AZMI monitoring well downhole P/T gauge	Redundant measurement, no direct regulatory link	Potential to detect pressure anomaly in AZMI in case of leakage; will require careful analysis due to false positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously
AZMI monitoring well fluid sampling	§3625.A.4 §146.90d	Above UCZ fluid collection is recommended by guidelines	Annually

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Appendix F – Testing and Monitoring

- Appendix F-1 USDW Monitoring Well Plan Map
- Appendix F-2 AZMI Monitoring Well Plan Map
- Appendix F-3 USDW Monitoring Well No. 001 Schematic
- Appendix F-4 USDW Monitoring Well No. 002 Schematic
- Appendix F-5 USDW Monitoring Well No. 003 Schematic
- Appendix F-6 USDW Monitoring Well No. 004 Schematic
- Appendix F-7 USDW Monitoring Well No. 005 Schematic
- Appendix F-8 AZMI Monitoring Well No. 001 Schematic
- Appendix F-9 AZMI Monitoring Well No. 002 Schematic

5.6 References

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