Underground Injection Control – Class VI Permit Application for

Cronos No. 1 and Rhea No. 1

Jefferson County, Texas

SECTION 5 – TESTING AND MONITORING PLAN

February 2024

SECTION 5 – TESTING AND MONITORING PLAN

TABLE OF CONTENTS

Figures

Tables

5.1 Introduction

The operating plans for the proposed Titan Carbon Sequestration Project (Titan Project) injection wells Cronos No. 1 and Rhea No. 1 include robust testing and monitoring programs in accordance with promulgated regulations, which are designed to satisfy the requirements of 16 Texas Administrative Code (16 TAC) ***§*5.203(j)** and Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.90**. This plan will begin before CO_2 injection 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 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 also 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 the USDWs. This section discusses the key details of this plan.

5.2 Record Keeping and Reporting Requirements

In compliance with 16 TAC **§5.207** [40 CFR **§146.91**], Titan Carbon Sequestration, LLC (Titan) will provide routine reports to the Underground Injection Control (UIC) Program director (UIC Director). The report contents and submittal frequencies are as follows.

Per-Occurrence Reporting:

- 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 the event
- Any evidence that the injected CO_2 stream or associated pressure front may endanger a USDW
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 5 working days of the event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of the event
- Any significant data that indicate the presence of leaks in the well or lack of confinement to the injection zone
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 5 working days of the 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
- Any new wells installed at the facility and the type, location, number and information required by 16 TAC **§5.203(e)**
- 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 the event
    - Written Notification – Reported within 72 hours of the event
- Description of any event that triggers a shutoff device either downhole or at the surface and the response taken
    - Verbal Notification – Reported within 24 hours of the event
    - Written Notification – Reported within 72 hours of the event
- Results of injection pressure and injection rate monitoring of each injection well on TRRC Form H-10, Annual Disposal/Injection Well Monitoring Report

Semiannual Reports:

- Summary of wellhead pressure monitoring
- Any changes to the source of the CO_2 stream
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data
- Monthly average, maximum and minimum values of injection pressure, flow rate, temperature, volume, and annular pressure
- Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit
- Monthly volume and/or mass of the CO_2 stream injected during the reporting period, and the volume injected cumulatively during the life of the project
- Monthly annulus fluid volume added
- Results of any monitoring, as described in this section

Annual Reports:

- Any corrective action performed
- Recalculated area of review (AOR) or statement confirming that monitoring and operational data supports the current delineation of the AOR on file with the regulatory authority
- Proof of good faith claim to sufficient property rights for storage facility operation
- Metric tons of CO_2 injected

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

- Any well workover

- Any test of the injection wells conducted, if required by the UIC Director
- Any periodic mechanical integrity tests

Notification to the UIC authority [16 TAC **§5.206(c)**], in writing, 30 days in advance of the following:

- Any planned workover
- Any planned stimulation activities
- Any other planned test of the injection wells

Titan will submit the above reports, submittals, and notifications to the Environmental Protection Agency (EPA) and Texas Railroad Commission (TRRC) and ensure that such records are retained throughout the life of the project. In accordance with 16 TAC **§5.207(e)** [40 CFR **§146.91(f)**], these records will be maintained for 10 years after site closure. The records will be delivered to the UIC Director upon request after the retention period. Monitoring data will be retained for 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 <u>Testing Plan Review and Updates</u>

In accordance with 16 TAC **§5.207(a)(3)** [40 CFR **§146.90(j)**], the Testing and Monitoring Plan will be reviewed and revised at least every 5 years or as otherwise required to incorporate collected monitoring data. Plan amendments will also be submitted within 1 year of an 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 <u>Testing Strategies</u>

5.4.1 Initial Step-Rate Injectivity Test

Prior to the commencement of CO_2 injection, Titan will conduct a step-rate injectivity test to measure the fracture gradient of the proposed injection wells, Cronos No. 1 and Rhea No. 1, in compliance with 16 TAC **§5.203(f)(2)(A)** [40 CFR **§146.87(d)(1)**] and 16 TAC **§5.203(f)(2)(C)** [40 CFR **§146.87(e)(3)**]. Pressure and temperature gauges, plus fiber optic temperature and acoustic sensing, will be run and cemented behind the [redacted] casing from surface to the total depth of the wellbore. A surface gauge with continuous readout will also be installed. All gauges will be calibrated prior to the test. Initial bottomhole pressure and temperature readings must be taken prior to beginning injection.

The step-rate test will be performed using brine. Brine injection rates observed during step-rate testing can be converted to the equivalent CO_2 injection rate by accounting for the difference in fluid properties. The injection rate can be converted from a volumetric rate to a mass rate (i.e., barrels per day (bbl/D) to standard cubic feet per day (scf/D). The mass rate is more suitable for measuring a compressible fluid such as CO_2.

The densities of the CO_2 at standard conditions and in the reservoir are modeled using the Reference Fluid Thermodynamic and Transport Properties Database (REFPROP, Ver. 10.0), a software program developed by the National Institute of Standards and Technology. This program references thermodynamic, physical, and transport properties of various fluids and fluid mixtures, and implements fluid models to calculate properties at variable temperatures and pressures throughout the liquid, gas, and supercritical states. The most accurate available models are included for 147 industrially important fluids. A wide range of tables and plots can be created within the software to display fluid properties at varying conditions. Equations 1 through 3 are key equations used within the REFPROP software.

(Eq. 1) $$Qm = \frac{Qv * \rho BH}{\rho SC}$$

(Eq. 2) $\rho_{BH} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow$ from $REFPROP\ software$

(Eq. 3) $\rho_{SC} = f(T_{SC}, P_{SC}, Fluid\ Composition) \leftarrow$ from $REFPROP\ software$

Where:

Qv = volumetric flow rate (bbl/day)

Qm = mass flow rate (scf/day)

T_{BH} = temperature at bottomhole (°F)

P_{BH} = pressure at bottomhole, pounds per square inch (psi)

ρ_{BH} = CO_2 density at bottomhole conditions, pounds per cubic foot (lb/ft^3)

T_{SC} = temperature at standard conditions (°F)

P_{SC} = pressure at standard conditions (psi)

ρ_{SC} = CO_2 density at standard conditions (lb/ft^3)

5.4.1.1 Testing Method

Specific wellbore and injection zone properties will define the final test parameters. The following test method outlines the expected test injection rates and times. Brine injection will begin at less than 1 barrel per minute (bpm) and be held for a [redacted]. The injection rates will be stepped up in increments until at least three measurements are taken, both below and above the estimated formation fracture-initiation pressure—or to a maximum rate of [redacted]. *Each stage duration will be based on the time required for the bottomhole pressure for the initial step to stabilize*. Table 5-1 lists the proposed rates and total volumes planned for the step-rate test.

Table 5-1 – Proposed Step-Rate Injection Test

Step	Duration (min)	Rate (bpd)	Rate (bph)	Rate (bpm)	Volume (bbl)
[redacted]					

bph – barrels per hour

A plot of stabilized injection pressure vs. injection rate at each step should graphically represent a linearly sloped line, until the fracture initiation pressure is exceeded. Figure 5-1 is a graphical representation of an example step-rate test.

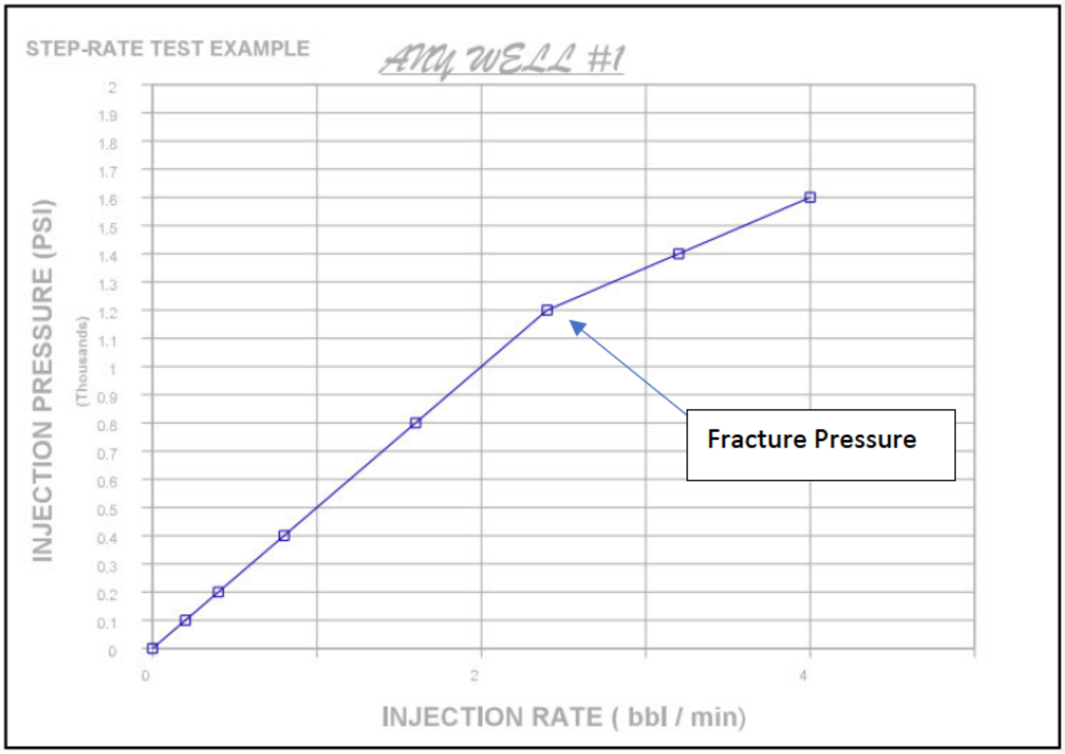

Figure 5-1 – Example Step-Rate Injectivity Test[1]

Upon reaching a stabilized pressure after completing the final step, pressures will be recorded at the highest frequency of the gauge for a period indicated by the step-up phase of testing, to calculate the rate of pressure bleed-off.

5.4.2 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 16 TAC **§5.203(h)(1)(C)** [40 CFR **§146.89(b)**], Titan will ensure the mechanical integrity of both injection wells by performing annulus pressure tests (1) after the wells have been completed, (2) prior to injection, and (3) every five years 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.

After the wells are completed, an annular pressure test will be performed prior to the start of injection, to demonstrate the mechanical integrity of the casing, tubing, and packer. An annulus pressure test will also be performed after any workover operation involving the removal and replacement of the tubing and packer. The annulus will be pressured to a minimum of 500 psi fluid pressure. A block valve will be used to isolate the test pressure source from the test pressure gauge once the test has begun. All ports into the casing annulus—other than the one monitored by the test pressure gauge—will be closed. The test pressure will be monitored and recorded for

[1] https://www.epa.gov/sites/default/files/documents/INFO-StepRateTest.pdf

a minimum of 30 minutes. The test pressure gauge will be of sufficient sensitivity to indicate a loss of 5%. Any loss of test pressure more than 5% during the minimum 30 minutes will indicate a lack of mechanical integrity.

All annulus pressure test results will be submitted to the TRRC/EPA on Form H-5 within 30 days of log run completion. This test will be performed at least every 5 years.

5.4.3 External Mechanical Integrity Testing – Temperature Log

Titan will perform external mechanical integrity tests (MITs) annually, to meet the requirements of 16 TAC **§5.203(h)(2)** [40 CFR **§146.89(c)**], by running a temperature log through tubing or by using the distributed temperature sensing (DTS) system installed on the fiber optic system. Temperature logs will be run prior to beginning injection operations, to establish the baseline to compare against future logs. Prior to running the temperature logs, the wells will be shut in long enough— approximately 36 hours—to stabilize temperatures. Satisfactory mechanical integrity is demonstrated by the proper correlation between the baseline and subsequent logs. All temperature logs will be reported to the UIC Director within 30 days of the log run.

<u>Temperature Log Procedure</u>
Prior to injection, the wells will be shut in for at least 36 hours, and a temperature log will be run in the wells to establish a baseline temperature survey. This baseline survey will be compared against temperature surveys throughout the life of the wells, to determine fluid flow outside the casing. In all future temperature logs, a stabilization period will be reached to compare any differences in the log. Distributed temperature sensing fiber may also be used for the required temperature analysis.

When conducting a temperature survey via wireline, the tool will log from the surface to the total depth (TD) of the wells. No logging runs should precede the temperature log, to ensure static conditions in the wellbore. The recommended logging speed is 30 feet (ft) per minute, and all depths should be zeroed to the bradenhead flange. The following list highlights the general procedure for the wireline-temperature logging operation for the proposed injection wells:

1. Allow the well to stabilize for 36 hours.
2. Rig up the wireline unit to the wellhead and make up the logging tool (temperature probe and casing collar locator (CCL)).
3. Zero the end of the tool string at the bradenhead flange.
4. Run in the hole while logging from surface to TD at 30 ft per minute. Correlate collar depths to the CCL.
5. Pull out of hole and rig down wireline unit.

Once the temperature log is processed, the data will be analyzed in conjunction with the baseline and other temperature logs. A differential temperature trend will be calculated and reported. Include the new log and the baseline log on a report as well as a track—to calculate the differential temperature.

5.4.4 Pressure Falloff Testing

Titan will perform a required pressure falloff test at least every 5 years to meet the requirements of 16 TAC **§5.203(j)(2)(G)** [40 CFR **§146.90(f)**]. This test will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases. Parameters obtained from the falloff tests will be compared to those determined from the computational modeling and previous tests, for indications of fluid leakage during the test.

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 falloff test, and data will be continuously recorded during testing. After the wells are 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 falloff period will end once the pressure-decay data plotted on a semi-log plot is a straight line, indicating that radial-flow conditions have been reached.

Detailed Pressure Falloff Test Procedure:

1. Prior to testing, keep the injection rate and pressure as constant as practical and continuously recorded.
    a. The injection rate should be high enough and maintained for a duration sufficient to produce a measurable pressure transient that will result in a valid falloff test.
    b. Offset wells should be shut in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
    c. [redacted]
2. Stop injection and shut in the wells completely.
    a. This shut-in should occur over the shortest time possible.
3. During the shut-in period, continue to record temperatures and pressures at the highest obtainable frequency.
    a. The shut-in period should be long enough to observe a straight line of pressure decay on a semi-log plot (i.e., radial flow is achieved). The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the falloff portion of the test should be designed to reach radial flow, and to sustain a time frame sufficient for analysis of the radial flow period.
    b. A general rule of thumb is to run the test for three to five times the amount of time required to reach radial flow conditions.

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 falloff tests performed prior to initial injection, with later tests. The effects of two-phase flow will also be considered. The well parameters resulting from falloff testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AOR reevaluation is necessary. Results of the pressure falloff test will be reported to the UIC Director within 30 days of the test.

5.4.4.3 Quality Assurance/Quality Control

All surface field equipment will undergo inspection and testing prior to operation. The pressure gauges used in the falloff test will be calibrated according to manufacturers' instructions. Documentation certifying proper calibration will also be enclosed with the test results. [redacted]

5.4.5 Cement Evaluation and Casing Inspection Logs

In accordance with 16 TAC **§5.203(h)(2)** [40 CFR **§146.89(d)**], a comprehensive cased-hole logging suite will be run on the long-string casing at the time of initial well completion. This suite of logs will include a cement bond log and a multiple-armed caliper to establish the condition of the casing metal. This survey will characterize the original state of the wellbore materials.

Casing inspection logs will be run at least every five years if a log has not been obtained in the interim. These logs will be performed, through tubing on wireline if tubing and packer are not moved and whenever tubing is removed for workover operations. The following tools will be run at that time:

- A 5-year casing inspection:
    - Casing section below the packer:
        - Multiple-armed calipers to measure the inner diameter (ID) of the casing as the tool is raised or lowered into the well
        - Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
        - Electromagnetic tools that measure the magnetic flux of the tubular and can provide mapped circumferential images to indicate potential pitting
    - Casing section without tubing in the hole
    - Casing section from packer to surface:
        - Through-tubing casing inspection log
- Conventional casing inspection logs will be run if tubing is removed, consisting of the following:

- Multiple-armed calipers to measure the ID of the casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing as well as cement bonding
- Electromagnetic tools that measure the magnetic flux of the tubular and can provide mapped circumferential images to indicate potential pitting

Titan will provide a schedule of all logging plans to the UIC Director at least 30 days before conducting the first test. Notice will be provided at least 48 hours in advance of such activity.

5.4.5.1 Casing-Log Equipment Overview

Through-tubing logging technology provides the ability to evaluate casing deformation and curve-deviation measurements in conjunction with other well-integrity tools, such as multi-finger calipers and multiple pipe-thickness logging tools. This technology provides quality measurements without requiring the removal of the tubing and packer (Yang et al., 2021).

The following descriptions of the through-tubing logging tools that will be run are provided for informational purposes. The final vendor will be selected before operations, based on availability and commercial considerations.

The instruments listed in Table 5-2 use pulsed eddy current (PEC) decay technology to measure the thicknesses of multiple concentric tubulars. Basic PEC decay technology theory is discussed further below. These tools can be run stand-alone or combined with other well-integrity and correlation instruments—such as multi-finger imaging caliper, temperature, noise, pressure, fluid density, capacitance, flowmeter, gamma ray, and CCL.

The through-tubing PEC decay measurements are not affected by wellbore fluid types, chemical precipitates, or other foreign material deposits. They are also not affected by the type or distribution of annular materials, such as cement, mud, liquid, or gas.

Table 5-2 – PEC Tool List

Pulsed Eddy Current Decay Thickness Instruments					
Tool	Tool O.D.	Max # concentric pipes	Max O.D.	Max Combined Wall Thicknesses	Ratings (degF/K psi)
MTD-B/C	1-11/16"	2	10-3/4"	1.75"	350/15
MTD-G	1-11/16"	3	16"	2.5"	350/15
ePDT-II	2" / 1-11/16"	3-5	30" / 18-5/8"	3.5"	350/20

"O.D." = outer diameter
degF/K = degrees Fahrenheit per thousand pounds per square inch

Logging speeds depend on the size and number of tubulars to be logged. In general, multiple tubulars and larger sizes will necessitate slower data-acquisition speeds, which range from 30 ft per minute to 5 ft per minute, based on the complexity of the wellbore configuration.

The through-tubing PEC decay instruments measure the increase or decrease of metal thickness for each concentric tubular. The PEC decay data combined with inspection of the tubular's ID, using an imaging caliper or other methods, can reliably predict the inside vs. outside location of corrosion or flaws on the innermost tubular. Internal wear based on drilling or other known causes of internal damage is readily assessed, assuming that the measured metal loss in such cases is "internal."

The degree of penetration is reported in percentage of wall loss from both the nominal and absolute values of metal thickness, expressed in inches or millimeters. Because of well-understood, long-established PEC decay physics principles, reported metal gain or loss is assumed to be distributed evenly around the pipe's circumference.

The through-tubing PEC decay instruments measure the increase or decrease of metal thickness, due to both internal and external corrosion effects. This overall metal thickness/degree of penetration is valid in identifying areas of concern with well integrity. Additionally, integrity assessment of the injection tubulars (i.e., tubing[s] and first casing) is only part of whether a wellbore and its associated tubulars are in such a condition as to be protective of public health, safety, and the environment. The newer-generation through-tubing PEC decay instruments provide an opportunity to assess the state of the protection tubulars (i.e., second casing, surface casing, etc.).

5.4.5.2 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of the proposed Titan injection wells Cronos No. 1 and Rhea No. 1—and interpreted by a knowledgeable log analyst—will be submitted to the UIC Director in accordance with 16 TAC **5.203(h)(2)** [40 CFR **§146.87(a)**].

5.5 Monitoring Programs

5.5.1 Monitoring Overview

Table 5-3 summarizes the various measurements discussed in the Testing and Monitoring Plan.

Table 5-3 – Testing and Monitoring Plan Measurements

Monitoring Type	Monitoring Program	Location	Frequency
CO_2 Injection Stream Composition	• CO_2 sampling station	CO_2 meter run	Quarterly
Corrosion Monitoring	• Corrosion coupon system	Facility flowline	Quarterly
Continuous Recording of Injection Pressure, Rate, and Volume	• Surface pressure and temperature gauges • Coriolis mass flowmeter	Wellhead	Continuous
Well Annulus Pressure Between Tubing and Casing	• Annular pressure gauge	Wellhead	Continuous
Groundwater Monitoring	• USDW monitoring wells • Groundwater monitoring wells	Facility	Annually first 5 years, then every 5 years until plume stabilizes
Above Confining Zone (ACZ) Monitoring	• Fluid samples • Pressures	Above-zone monitoring (AZM) wells	Pressure – continuously; fluid – as needed, if indicated from pressure response
Direct Reservoir Monitoring	• Pressure/temperature gauges on TEC cable installed on outside of casing	Cronos No. 1 and Rhea No. 1	Continuously
Indirect Reservoir Monitoring	• Vertical seismic profile (VSP) surveys	Facility	Years 1 and 5 after injection begins, then every 5 years until plume stabilizes
Internal and External Mechanical Integrity	• Annulus pressure test • Temperature pulsed neutron logs • Casing pressure test • Pressure falloff test • Ultrasonic logs	Cronos No. 1 and Rhea No. 1	• Every 5 years • Annually • 5 years • 5 years • 5 years

5.5.2 Continuous Injection Stream Physical Monitoring

Titan will ensure continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 16 TAC **§5.203(j)(2)(B)** [40 CFR **§146.90(b)**]. A Supervisory Control and Data Acquisition (SCADA) system will facilitate the operational data collection and monitoring for the full sequestration site—consisting of the pipeline, injection wells, and AZM wells.

The pressure and temperature of the injected carbon dioxide stream will be continuously monitored—using digital pressure gauges installed in the CO_2 pipeline, near its interface with the wellhead—and connected to the SCADA system on-site. A Coriolis mass flow transmitter will be installed on the injection wells to measure the mass flow rate of CO_2 injected. The flow transmitter will be connected to the CO_2 storage site's SCADA system to continuously monitor and control the rate of CO_2 injection.

Reservoir temperatures and pressures will be measured through gauges installed on a fiber optic system embedded in the cemented annulus behind the long-string casing. The gauges are described in detail in *Section 5.5.9*.

To meet the requirements of 16 TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], automatic shut-off systems and alarms will be installed to alert the operator and/or shut in the well when operating parameters, such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients. A change of 10% in the annular pressure during injection operations will result in a shutdown event.

5.5.2.1 Analytical Methods

Continuously monitored parameters will be reviewed and interpreted regularly, to ensure the parameters are within permitted limits. The data will also be reviewed for trends to help identify the need for equipment maintenance or calibration. Monitoring results will be included in the semiannual reports.

5.5.2.2 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

CO_2 Mass Rate to Volumetric Injection-Rate Calculation Methodology

Mass flow rates observed during CO_2 injection can be converted to a volumetric flow rate by considering the density of the fluid. The pressure, temperature, and fluid composition are required to calculate density at specific conditions. REFPROP™ or similar fluid property calculation software may be used to determine density.

Variables Defined:

Q_m = Mass Flow Rate (lb/day)
T_bh = Temperature at Bottom Hole
P_{bh} = Pressure at Bottom Hole
ρ_{bh} = CO2 Density at Bottom Hole Conditions (lb/ft^3)
Q_{vbh} = Volumetric Flow Rate at Bottom Hole (ft^3/day)

Equations:

(Eq. 4) $$\rho_{bh} = f(T_{BH}, P_{BH}, Fluid\ Composition) \leftarrow REFPROP\ software$$

(Eq. 5) $$Q_{vbh} = \frac{Q_m}{\rho_{bh}}$$

5.5.3 Injection-Stream Composition Monitoring

In accordance with 16 TAC **§5.203(j)(2)(A)** [40 CFR **§146.90(a)**] requirements, Titan 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 of the parameters listed in Table 5-4, plus continuous pressure and temperature analysis.

5.5.3.1 Sampling Methods

In a location representative of injection conditions, CO_2 stream samples will be collected from the CO_2 pipeline. A sampling station will be connected to the pipeline inlet meter at a sampling manifold. Sampling cylinders will be purged with the injectate gas to expel laboratory-added gas, or vacuum cylinders will be used to obtain the samples. The samples will subsequently be sent to a laboratory for analysis.

5.5.3.2 Parameters Measured

Table 5-4 also lists the injection stream parameters that will be measured, plus the frequency and methods used.

Table 5-4 – 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
CO_2 (%)	Quarterly	Lab analysis
Water (lb/MMscf)	Quarterly	Lab analysis
Oxygen (%)	Quarterly	Lab analysis
Sulfur (ppm)	Quarterly	Lab analysis
Methane (%)	Quarterly	Lab analysis
SO_2 (%)	Quarterly	Lab analysis
NO_x (%)	Quarterly	Lab analysis

Parameter/Analyte	Frequency	Method
Ethane (%)	Quarterly	Lab analysis
Other Hydrocarbons (%)	Quarterly	Lab analysis
Hydrogen Sulfide (ppm)	Quarterly	Lab analysis
Benzene (%)	Quarterly	Lab analysis

*MMscf – million standard cubic feet
ppm – parts per million

5.5.3.3 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.4 Corrosion Coupon Monitoring

Titan will not only conduct corrosion monitoring of the tubing and the wells' casing materials—to meet 16 TAC **§5.203(j)(2)(C)** [40 CFR **§146.90(c)**] requirements—but also implement a corrosion coupon monitoring system. This system will be evaluated quarterly and casing inspection logs performed at least every 5 years at the time of permit renewal if a log has not been obtained in the interim. If plume surveys indicate it is time to recomplete uphole to a shallower subsection, then the tubing and packer will be removed and inspected, and a casing inspection logging suite will be run. If abandonment of a subsection is not warranted at the time of permit renewal, then a through-tubing inspection will be performed.

5.5.4.1 Sampling Methods

Corrosion coupons, comprised of the same material as the injection tubing and production casing, will be exposed to the conditions of the CO_2 flow in the pipeline, in a flow loop installed off the pipeline. 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 calculated by applying a weight-loss calculation method that divides the weight loss recorded during the exposure period by the period duration.

5.5.4.2 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.5 Groundwater Quality Monitoring

To meet 16 TAC **§5.203(j)(2)(C)** [40 CFR **§146.90(d)**] requirements, groundwater quality and geochemical monitoring above the confining zone will be conducted, the purpose of which is to detect potential changes that may result from fluid leakage out of the injection zone. As discussed in *Section 1.9.2*, [redacted] Titan therefore plans to drill two groundwater monitoring wells on the property, placing them on the same well pad as the injectors, to measure any change from baseline parameters that would indicate the migration of CO_2 into the USDW.

The well locations are shown in Figure 5-2 and listed in Table 5-5. During the final planning of the well pads, the locations of the AZM and USDW monitoring wells could change slightly. Well construction and drilling details, along with schematics, are included in *Appendix F*.

[redacted]

Figure 5-2 – Location of the Titan Project Monitoring Wells

Table 5-5 – USDW Monitoring Well Details

Location Info	TCS WM No. 1	TCS WM No. 2
NAD 83 (2011) Latitude	[redacted]	
NAD 83 (2011) Longitude		
Total Depth (ft)		
Type		

*NAD 83 – North American Datum of 1983

A detailed wellbore schematic for TCS WM No. 1 is displayed in Figure 5-3 as a representative example of such wells. Wellbore schematics of TCS WM No. 1 and No. 2 are provided in *Appendix F*.

As discussed in *Section 3.3.2*, the critical pressure front [redacted]

[redacted]

Figure 5-3 – TCS WM No. 1 Schematic

5.5.5.1 Parameters

Samples will be taken annually for the first 5 years, then every 5 years subsequently, with parameters to be measured as shown in Table 5-6.

Table 5-6 – USDW and AZM Monitoring-Well Sampling Parameters Measured

Parameter/Analyte	Frequency
Aqueous and pure-phase carbon dioxide	Annually first 5 years; subsequently, every 5 years
Total dissolved solids (TDS)	
pH	
Specific conductivity (SC)	
Temperature	
Density	
Other parameters, including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	

5.5.5.2 Sampling Methods

Fluid samples in the groundwater monitoring wells will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container, to prevent any losses of dissolved gases. Prior to sampling, the wells will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the wells. A U-tube sampling system or submersible pump will be lowered to the monitored zone via wireline or slickline, and the rate of sample collection should not exceed the rate at which the wells were purged.

5.5.5.3 Analytical Methods

Water samples will be tested and results maintained for the parameters listed above. If any impurities exist in the injectate, testing of those components should be included in the groundwater analysis to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database.

Trends that may indicate fluid leakage include the following:

- Change in TDS
- Changing signature of major anions and cations
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of injectate impurities
- Increase concentration of leached constituents
- Increased reservoir pressure and/or static water levels

5.5.5.4 Deviation Response

In any event where the sampling or analysis indicates a variance from the normal baseline, the regulators will be notified, an investigation will take place, and the appropriate response including any corrective action will be determined and presented to the regulators for approval and implementation.

5.5.5.5 Laboratory to Be Used/Chain-of-Custody Procedures

Water samples will be sent to an EPA-approved laboratory. Standard chain-of-custody procedures will be followed, and records maintained, to allow a full reconstruction of how the samples were collected, stored, and transported—and will include details of any problems encountered.

5.5.5.6 Quality Assurance and Surveillance Measures

Duplicate samples and trip blanks for quality assurance/quality control (QA/QC) purposes will be collected and used to validate test results and ensure samples are free of contamination.

5.5.5.7 Plan for Guaranteeing Access to All Monitoring Locations

As the locations are in marsh wetlands, access to the wells will be extremely restricted. Nevertheless, the wells will be capped and locked out to prevent any unauthorized access to the well.

5.5.6 Above-Zone Monitoring Well

In addition to the two USDW monitoring wells, two AZM wells—Atlas No. 1 and Andes No. 1—will be drilled to a depth corresponding to the first permeable formation above the upper confining zone (UCZ). [redacted] shown in Figure 5-2 (*Section 5.5.5*)—the details of which are provided in Table 5-7.

Table 5-7 – AZM Well Location Details

Location Info	Atlas No. 1	Andes No. 1
NAD 83 (2011) Latitude	[redacted]	
NAD 83 (2011) Longitude		
Total Depth (ft)		
Type		

5.5.6.1 Pressure Monitoring

Titan will use a downhole pressure gauge to continuously monitor the pressure of the first permeable formation identified above the UCZ in the AZM wells. Deviations from baseline pressures after the start of injection will initiate further review in the area. This review includes both a study to rule out sensor drift, and a comparison to the pressure trend observed prior to injection—the latter providing insights into potential far-field activities in the same zone. [redacted] This benign effect would also be modeled and compared against observations, to further assess the likelihood of the pressure response indicating leakage.

5.5.6.2 Fluid Sampling

While the main purpose of these AZM wells will be to continuously monitor the pressure of the first mappable sand identified above the UCZ, fluid samples can, if necessary, be obtained from this well.

A detailed wellbore schematic for Titan's Atlas No. 1 is shown in Figure 5-4; Andes No. 1, in Figure 5-5. The wellbore schematics are also provided in *Appendix F*.

[redacted]

Figure 5-4 – Proposed Atlas No. 1 Schematic

[redacted]

Figure 5-5 – Proposed Andes No. 1 Schematic

5.5.7 Injection Plume and Pressure Front Tracking

Titan proposes a two-tiered system for plume and pressure-front tracking per the operational monitoring requirements of 16 TAC **§5.203(j)(2)(E)** [40 CFR **§146.90(g)**]. The critical pressure front will be directly monitored by continuously recording pressures and temperatures to calculate the extent of this pressure increase. The CO_2 plume will be indirectly monitored using seismic survey technology, such as a VSP.

Titan will use these methods to (1) verify reservoir conditions during injection, (2) track plume and critical pressure front migration, and (3) validate the reservoir model. Continuous pressure and temperature monitoring of the reservoir in the injection zone will allow for monitoring of reservoir conditions and inform calculations, while VSP surveys will determine the actual CO_2 plume migration. The VSP surveys will be run before injection initiation to establish a baseline, then run periodically as needed, at least every 5 years. Additionally, *after* injection has ended, the VSP survey will also be run every 5 years, or until plume stabilization has been verified. In the event that the plume extent exceeds the resolution of the VSP monitoring system, alternative methods may be employed, such as time-lapse 2D surveys.

5.5.7.1 <u>Direct Monitoring: Rate Transient Analysis</u>

Rate transient analysis and reservoir simulations, using known reservoir characteristics, enable more complex parameters to be calculated within the injection intervals. Direct monitoring will be based on continuous pressure, temperature, and injection rate data to calculate the properties of the reservoir and verify the plume model results. Pressure and temperature gauges will be run on TEC cable on the injection wells.

The reservoir model built during the site evaluation phase will be used to predictively monitor the reservoir conditions during injection operations. Through flow simulation and transient flow analyses, the reservoir model will be regularly updated with injection activity, to evaluate the injection stream's effect on reservoir conditions. This analysis can be performed to monitor the magnitude and extent of temperature and pressure changes within the injection zone. Continual monitoring of bottomhole pressures and temperatures combined with known reservoir parameters will be used to calculate reservoir conditions throughout the injection intervals.

Any shut-in periods can be observed and treated as a pressure falloff test. To do this during a shut-in period, the shut-in wellhead pressure, bottomhole pressure, and temperature readings will be recorded and used for pressure transient analysis of the reservoir. The analysis results will include the radius and magnitude of pressure falloff and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then confirm, and adjust as necessary, the previous model realizations.

Through predictive modeling and analysis of recorded pressure and temperature data, Titan can closely monitor the effect of the injection wells on the subsurface, to help ensure regulatory compliance and safety while contributing to informed decision-making.

5.5.7.2 Indirect Monitoring: Vertical Seismic Profile

Titan will use time-lapse VSP to indirectly monitor the CO_2 plume extent and development in accordance with 16 TAC **§5.203(j)(2)(E)** [40 CFR **§146.90(g)(2)**] requirements. A fiber optic cable with distributed acoustic sensing (DAS) will be installed and cemented in the annulus behind the long-string casing in both injection wells. This system will enable real-time reservoir monitoring using pressure and temperature gauges and the periodic VSP. The DAS fiber optic cable, designed with sensors as closely spaced as 1 meter apart, will be used to generate a VSP at the highest possible resolution. Maps of the carbon dioxide plume will be created from images generated using a walk-away seismic source. The data will be collected by acoustic monitoring in the injection wells and repositioning the surface acoustic source at the surface. The source locations will be determined based on well location and conditions.

As an example of where this technology has proven successful, Shell Canada used it to monitor plume movement at its Quest Project (Bacci et al., 2017). Figure 5-6 illustrates the acquisition pattern strategy employed for plume development surveys from two separate wells.

Figure 5-6 – Shell Canada Quest Project VSP Acquisition Patterns (Bacci et al., 2017)

Reservoir monitoring using time-lapse seismic surveys has an extensive history of use in tertiary oil-and-gas recovery. The methodology has undergone thorough testing in saline aquifers with the presence of CO_2. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from compressional changes in velocity between high CO_2 concentrations and formation gases and fluids. As CO_2 displaces formation fluids, the difference in acoustic impedance with time is an effective proxy for plume shape and can be visualized.

The work steps involved in a time-lapse VSP survey primarily include the following:

1. Rock Physics Model
2. Petro-Elastic Model
3. Feasibility
4. Baseline Survey (Data Acquisition)
5. Repeat/Time-Lapse Survey (Data Acquisition)
6. Interpretation

The following subsections discuss key portions of these work steps.

5.5.7.3 Rock Physics Model

A rock physics model is critical to time-lapse interpretation. This model establishes a relationship between fluid substitution and the change in acoustic impedance. It can be produced with high confidence, provided the reservoir characterization data is accurate. Changes in seismic response can be projected with a synthetic survey design and reservoir model, relying on the rock physics model to calculate formation fluid impact on acoustic impedance. This model determines if the monitoring program can facilitate the detection of expected formation-fluid substitutions.

Deterministic petrophysical analysis estimations can be used to forecast the dry mineral rock components before any saturation modeling. The model accounts for the following rock properties:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content
- Oil/gas residual (if any)

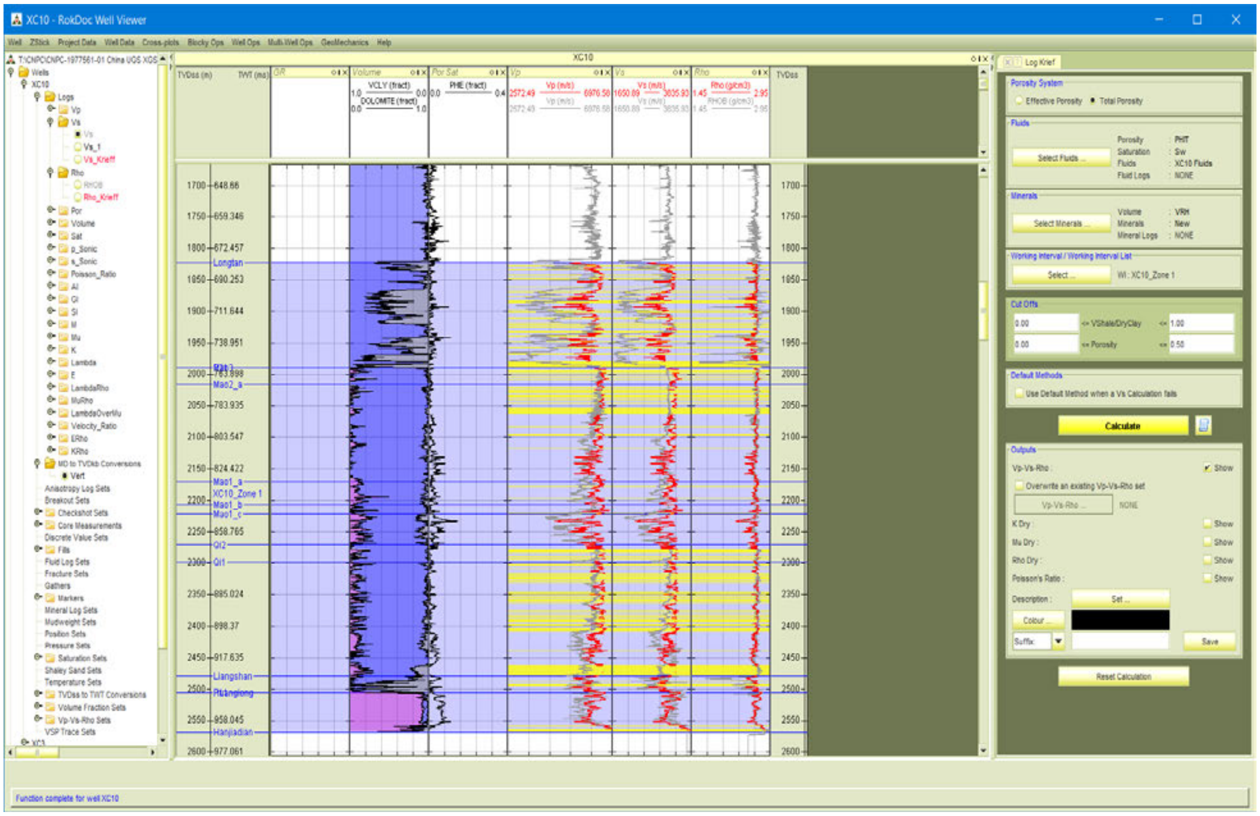

Figure 5-7 – RokDoc Well Viewer

The RokDoc Well Viewer (Figure 5-7), developed by Ikon Science, is an evaluation product that enables QC of the deterministic inversion of the reconstructed mineral content compared to the observed petrophysical response. The inversion allows for stabilizing inverted results, evaluating uncertainty in predicted attributes, and calculating in situ reservoir properties. The image shown here is an example of the software and is not representative of the geology at the Titan site.

5.5.7.4 Petro-Elastic Model

The rock physics model will generate a zero-order dry rock model, which is then used to establish a petro-elastic model by perturbing the elastic parameters for varying degrees of saturation.

Predicting velocity and density as functions of injectate saturation is the result of a petro-elastic model, an example of which is shown in Figure 5-8. The seismic response measured during VSP surveys can be determined using the acoustic impedance calculated from both elastic properties. Figure 5-8 is also an example from RokDoc Well Viewer and is not representative of the Titan Project.

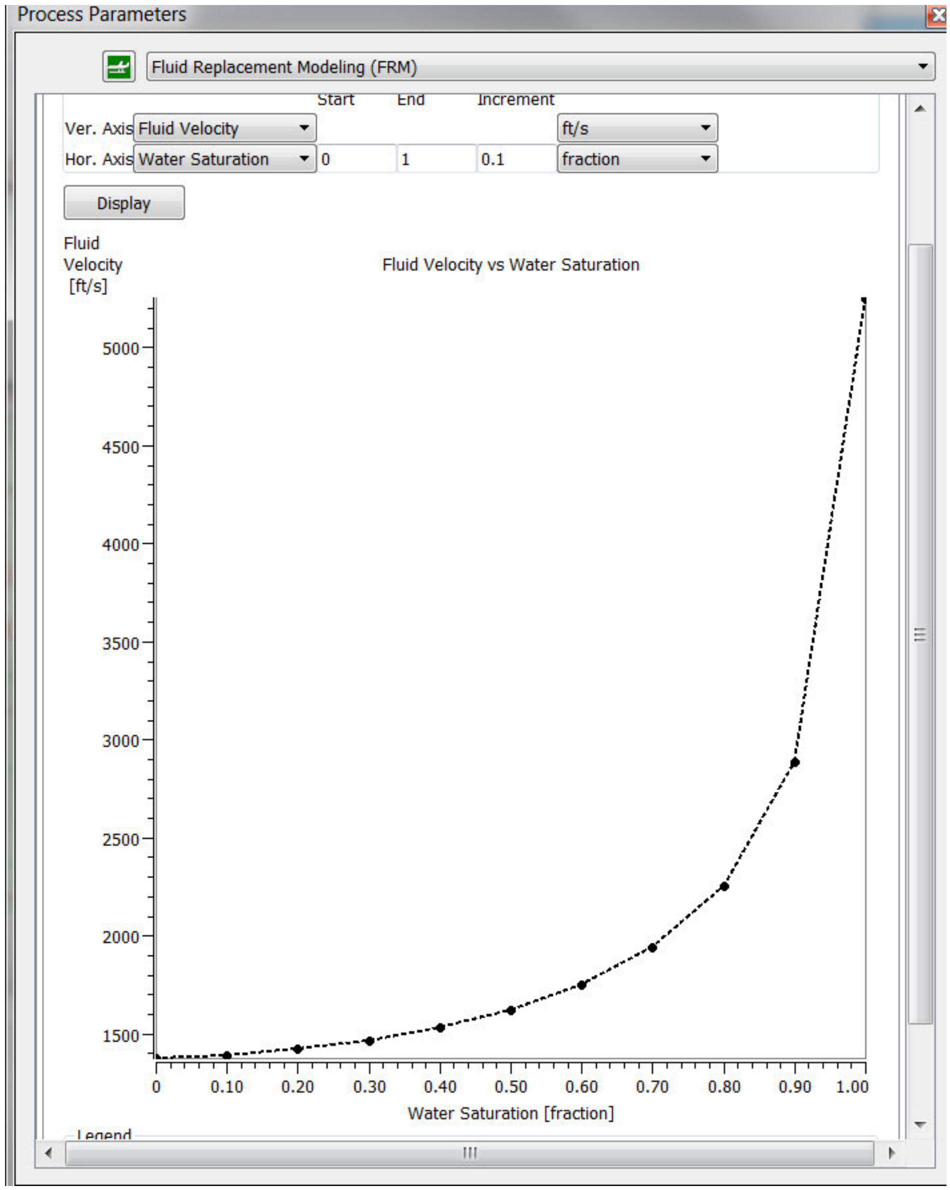

Figure 5-8 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

A feasibility study will be designed to determine if connate fluids replaced with CO_2 could be detected by the petro-elastic model. This study will be conducted after recovering core material from the stratigraphic test well. The CO_2 properties will be input into the model as replacement variables for openhole log readings that will be taken while drilling the stratigraphic test well for this project.

5.5.7.5 1D and 2D Models

Changes in the magnitude of the CO_2 plume are measured for different scenarios using 1D and 2D models. This section will detail the methodology used to generate these models.

Seismic waves that travel through the Earth are created with seismic surveys, and geophones listen for the waves that are subsequently reflected. The seismic waves can be made with a "shot," referring to explosives or other mechanical sources—most commonly a vibrator, which generates seismic waves by pounding a steel plate against the Earth. Geophones are recorders that detect sound waves reflected to the surface, and the data sent by geophones is then stored using seismographs. The geophones enable geophysicists to calculate the time it takes for seismic waves to reflect off transition zones between formations. Geoscientists can use the variation in sonar velocities to understand subsurface lithology.

Figure 5-9 depicts a standard VSP survey with a geophone configuration.

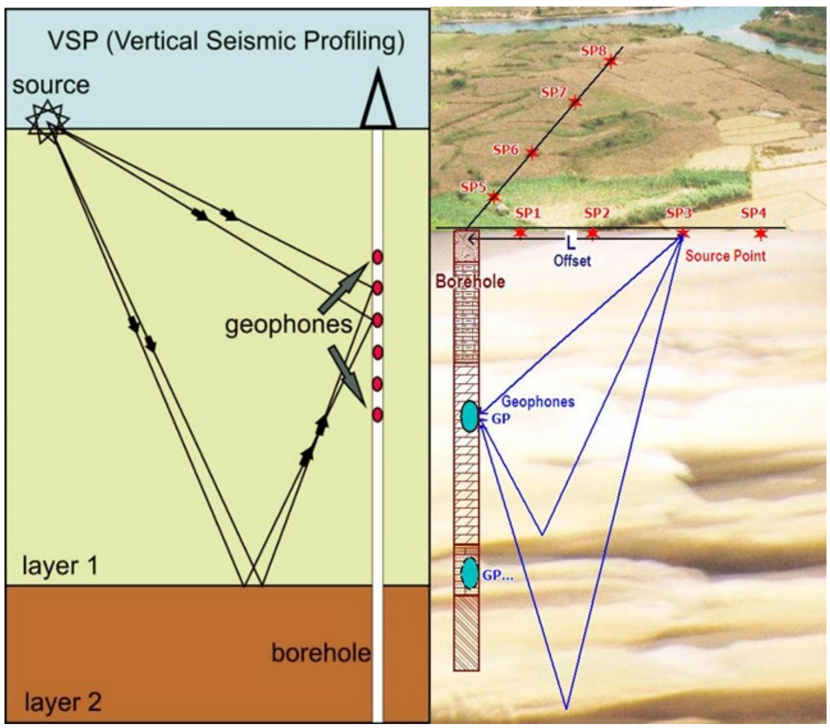

Figure 5-9 – Illustration of a Vertical Seismic Profile Survey

5.5.7.6 <u>1D Model</u>

The previously discussed principles apply to 1D seismic surveys. A standard method of obtaining 1D seismic data is with a checkshot survey, as illustrated in Figure 5-10. Geophones are situated vertically along the wellbore while all shots are fired from the surface. This placement allows the geophones to record seismic waves at different depths and provide measurements—at the highest levels of accuracy—of sonic velocities of the geologic layers affected by wellbore construction. These systems are commonly used to generate more accurate 2D, 3D, VSP, and 4D surveys.

The 1D survey methodology assumes that each formation is homogeneous in the horizontal direction; therefore, the surveys can only provide average sonic velocities. The 1D survey data can also be used to correct the sonic logs and create synthetic seismograms, which are used to forecast seismic responses of the subsurface. One variation of 1D seismic surveys is an acoustic log, which generates acoustic data along the wellbore using wireline sonic tools. Although the purposes of these logs differ from those of seismic surveys, they can provide a way to a 1D understanding of variation in velocities.

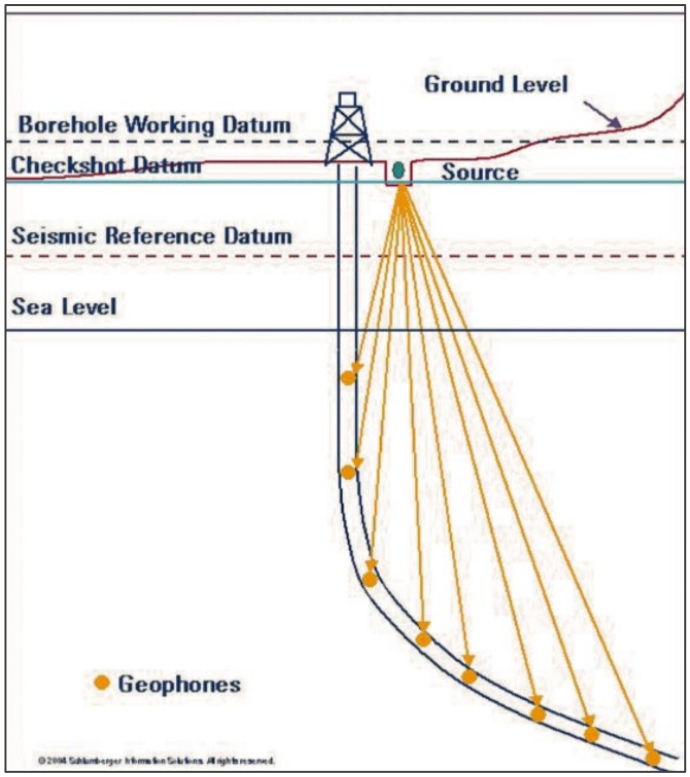

Figure 5-10 – Illustration of a Checkshot Survey

A 1D offset model will be constructed for each case, and differences in reflection amplitudes will be measured.

5.5.7.7 2D Model

A geologic model can be built once the results of a 1D model have been interpreted. The model reflects two saturation scenarios: one with connate formation fluid and the other with CO_2-replaced fluid.

Applying the same principles discussed in the previous section, 2D seismic surveys can provide a snapshot of a thin layer of the Earth's crust. The geophones for this survey are placed in a line along the surface and record reflected seismic waves from each formation. For best results, 2D surveys require setting multiple lines, ideally parallel to the structure dip and orthogonal to the geologic strike. The surveys provide subsurface information on various formations, faults, and other characteristics. Geologists can interpret contour lines and produce geologic maps using the intersection of numerous 2D surveys, which cost less and have less environmental impact than 3D surveys. They are commonly used to explore new areas and allow geologists to visualize the formations lying beneath the surface.

5.5.7.8 Processing Workflow and 4D Seismic Volume Determinations

To produce the final interpretation, CO_2 volume buildups from consecutive surveys will be observed over time. A time lapse or 4D model is created when VSP, 1D, 2D, or 3D dedicated seismic surveys are combined with a time element (i.e., surveys recorded at various time intervals—Year 1, Year 5, Year 10, etc.). The wheel spoke pattern of 2D survey lines, with the injector and VSP receiving fiber optic at its center, will provide coverage in all directions away from the injection well. Changing volumes of gas buildup, represented by either log shifts on the VSP, 1D, or 2D responses, or heat blooms (i.e., change in fluid density) on the 3D model, are identified in the time-lapse/4D interpretation of a seismic survey.

Figure 5-11 illustrates a basic workflow example:

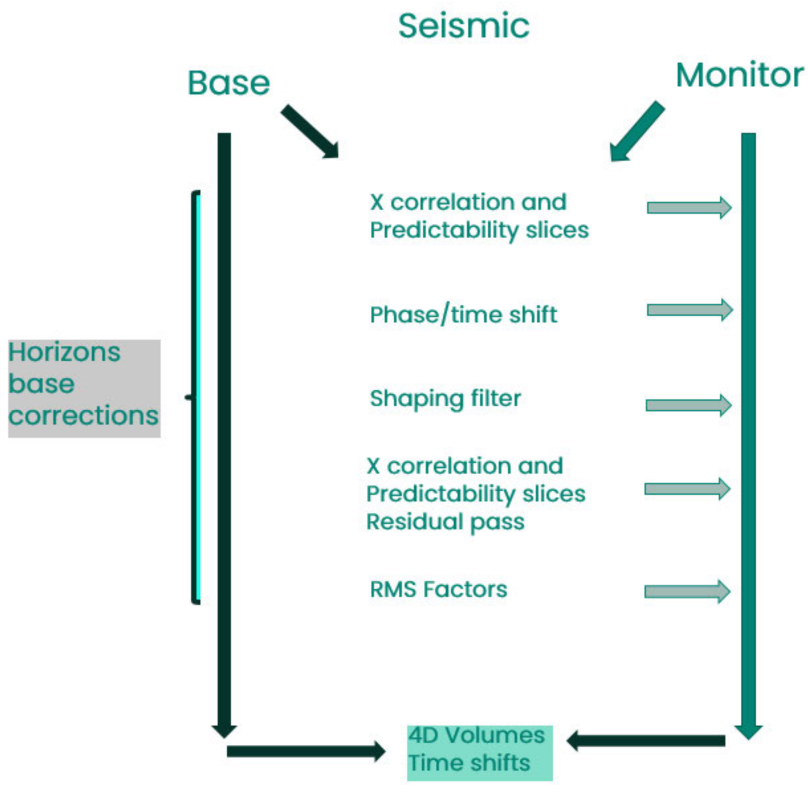

Figure 5-11 – A 4D Processing Workflow Diagram

The 3D horizon model is established from the base survey, and each successive survey creates a reflection differential mapped on the 3D model. The map is used to determine plume geometry, and the process is repeated in time increments to illustrate the time-lapsed development of the injectate plume.

To ensure consistency, all seismic volumes will be processed using the same software and for each workflow step outlined.

5.5.7.9 Inversion Workflow

Log data, post-stack seismic volumes, and a structural model will be used to invert baseline surveys, as Figure 5-12 shows. Later, monitor surveys will employ the same low component and residual corrections for consistency and the detection of changes over time—changes assumed to result from the injection operations.

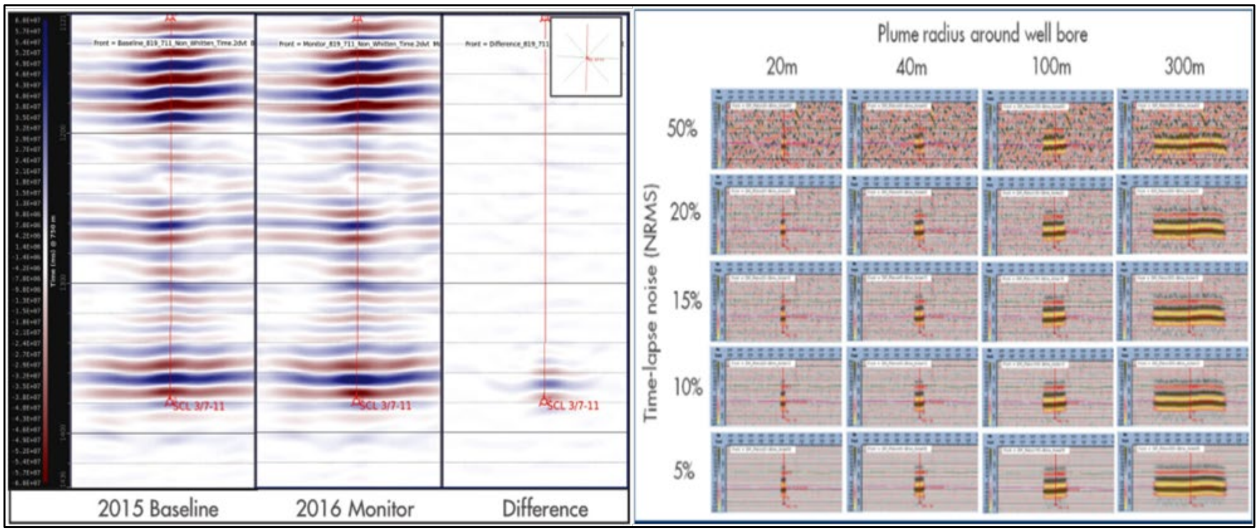

Figure 5-12 – Baseline and subsequent VSP used to determine the difference in amplitude attributed to CO_2 injection measured from the injector well itself. At right, estimation of the plume growth over time (Bacci et al. 2017).

5.5.7.10 Baseline Survey

Conducting a quality VSP baseline survey is critical, because it is the only opportunity to capture an image of the reservoir before injection operations or offset activity—either natural or man-made—impact it. Without this survey, the future interpretation of formation changes cannot be assessed. Also, the size of the baseline survey constrains the extent of plume measurement ability. It is essential to acquire a baseline survey with sufficient coverage if the initial reservoir models are not accurately forecasting plume migration. Titan will be obtaining this baseline survey prior to the commencement of injection.

5.5.7.11 Equipment Design and Setup

The proposed equipment for periodic survey operations to determine the CO_2 plume growth over time includes the time-lapse VSP, which uses a DAS fiber optic cable—to be connected to an interrogator box at the surface. The DAS system is synchronized to the seismic acquisition system controlling both the receiver (the DAS fiber optic array cemented in the injection wells) and the source.

5.5.8 Monitoring Schedule

The plume extent for the proposed Cronos No. 1 and Rhea No. 1 injection wells will be monitored using the DAS-VSP on the following schedule:

- The initial DAS-VSP survey will be conducted prior to the injection phase to capture the starting conditions for the formation brine.
- The first monitoring survey will be performed approximately 1 year after injection begins. The timing for this first survey is based on simulations that predict the plume extent will remain within the DAS-VSP imaging cone. This first survey allows early insights into the actual plume migration relative to the predicted model.
- Subsequent monitoring surveys will be conducted at Year 5 after the start of injection, then additional surveys will be performed at least every 5 years.
- During the PISC phase of the project, surveys will occur immediately after injection ceases into the last injection sand, and every 5 years after injection ceases. If the plume can be shown to have stabilized, additional DAS-VSP surveys will not be required. Pressures and temperatures will continue to be measured from the offset monitoring wells.

If the plume begins to reach the limit of the lateral extent of the VSP-survey resolution required to obtain quality results, time-lapse 2D seismic surveys will be performed to supplement the subsurface image from the VSP results.

5.5.9 Wellbore Overview

The proposed wellbores for both injection wells will have a [redacted]. conductor casing to a depth of about [redacted] ft. The surface casing for both wells will be [redacted] in. and will run below the USDW ([redacted] ft) to a depth of [redacted] ft. The surface casing will be cemented in place per EPA Class VI requirements. The production casing will be a [redacted] in. long-string run to a depth of [redacted] ft for Cronos No. 1 and [redacted] ft for Rhea No. 1. The [redacted] in. casing across the UCZ will be [redacted] material. This long-string casing will be cemented back to surface and comprised of CO_2-compatible cement from TD to [redacted] t for Cronos No. 1, and from TD to [redacted] ft for Rhea No. 1. Both injection wells will then have blended Portland cement from each of the previously mentioned depths to the surface. The injection string will be a [redacted] in. tubing string. The completion and monitoring assembly consists of a [redacted] in. [redacted] in. [redacted] packer (cut to release) that will initially be set at [redacted] ft for Cronos No. 1 and [redacted] ft for Rhea No. 1. Additionally, each well will have a subsurface injection valve (SSIV) just above the packer.

Figures 5-13 and 5-14 display the detailed proposed wellbore schematics for Cronos No. 1 and Rhea No. 1 (pages 38 and 39), respectively.

Pressure and temperature gauges, and distributed temperature and acoustic sensing with fiber optic cable will be installed on the OD of the [redacted] casing to TD. The system will be used to rapidly detect temperature profiles near the [redacted] in. casing, as well as to verify cement circulation during the cement job. The acoustic fiber will be used to monitor the CO_2 plume growth through seismic processing. The fiber monitoring system enables high-density strain monitoring of the wellbore and surrounding formation, to detect, localize, and classify reservoir compaction, shearing, and integrity issues.

The injection wells will have approximately 8,100 [redacted] ressure and temperature gauges and a separate fiber optic line installed on th [redacted] electronic gauges on the OD of the [redacted] casing and [redacted] he carriers to the ID, the gauges will be capable of continuous pressure and temperature monitoring of each injection, throughout the life of the project—assuming the injector perforations are not squeezed off with cement during plugging operations. Methods to avoid excessive cab [redacted]

[redacted]

Figure 5-13 – Proposed Wellbore Schematic for Cronos No. 1

[redacted]

Figure 5-14 – Proposed Wellbore Schematic for Rhea No. 1

5.5.9.1 Equipment Overview

The following discusses the typical hardware setup and use of in situ monitoring equipment for temperature, pressure, and seismic that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. The equipment described represents the technology that will be employed. Specific vendor-proprietary equipment details will be provided when the vendor is selected nearer to the time the wells are drilled.

[redacted]

[redacted]

Figure 5-15 – [redacted]

Subsurface Injection Valve

In accordance with TAC **§5.206(d)(2)(F)(i)** [40 CFR **§146.88(e)(2)**], an SSIV will be installed in the [redacted] tubing just above the packer. Figure 5-16 provides an illustration and description of the SSIV to be used.

[redacted]

Figure 5-16 – Subsurface Injection Valve

Monitoring Gauges
The following system components and specifications are provided as representative technologies for initial discussion purposes. Final selection of specific monitoring equipment and vendors will be determined prior to commencing drilling operations.

SureVIEW with CoreBright Optic Fiber
SureVIEW downhole cable uses CoreBright optical fiber, which leads the industry in resisting hydrogen darkening—the primary cause of failure for fiber optic systems in high-temperature applications. CoreBright is constructed from pure silica—minimizing hydrogen darkening—combined with a layer of hydrogen-absorbing gel. The Baker Hughes and GE Company (BHGE) standard SureVIEW fiber optic cable product is a 0.25-in. OD, heavy wall tubing-armor cable that encloses a 0.125 in. OD, thin wall tubing containing optical fiber. The armor is a corrosion-resistant alloy (CRA) tube, longitudinally welded and cold worked to its final diameter. It contains an extruded plastic filler (belting) that centralizes and provides a level of shock and vibration damping to the inner tube. The inner or fiber-in-metal tube (FIMT) contains up to 12 optical fibers immersed in thixotropic gel. Figure 5-17 illustrates the optical fiber, and Table 5-8 provides the specifications.

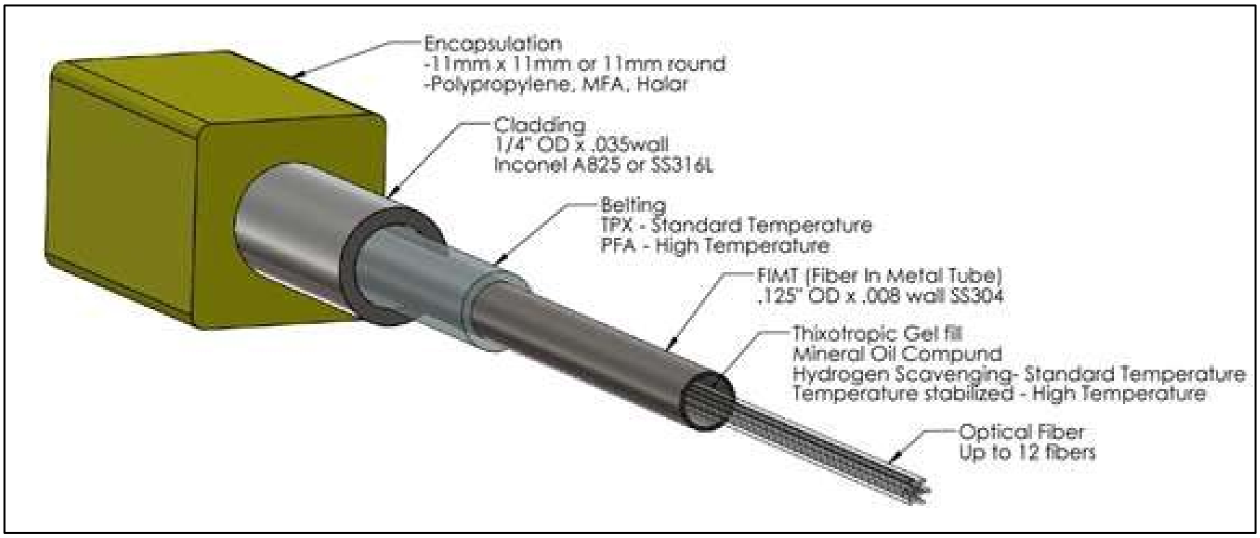

Figure 5-17 – SureVIEW with CoreBright Optical Fiber

Table 5-8 – SureVIEW Downhole Specifications

Description	Value	
Encapsulation	0.433 in.2 (11 mm2) or 0.41 in. round (11-mm OD)	
Cladding	0.250-in. (6.35-mm) OD × 0.035-in. (0.89-mm) wall	
FIMT diameter	0.125-in. (3.18-mm) OD	
Weight with polypropylene 11×11 encapsulation	154 lb/1,000 ft (230 kg/km)	
Weight without encapsulation	101 lb/1,000 ft (150 kg/km)	
Mechanical properties (70°F)*	**A825**	**SS 316L**
Tensile strength (lb)	2,687 (1,219 kg)	2,134 (968 kg)
Yield strength (lb)	2,090 (948 kg)	1,816 (824 kg)
Hydrostatic pressure (kPSI)	25 (17 kg/sq mm)	24 (16.8 kg/sq mm)
Burst pressure (kPSI)	32 (22 kg/sq mm)	22 (15.4 kg/sq mm)
Dynamic bend radius (in.)	14 (355 mm)	25 (635 mm)
Static bend radius (in.)	3 (82 mm)	6.3 (159 mm)
External collapse pressure (kPSI)	24.6 (1729 kg/sq cm)	17 (12.0 kg/sq mm)

*Materials listed should be derated for specific temperature applications. Contact Applications Engineering group for deration factors.

<u>SureVIEW DTS</u>

The SureVIEW DTS interrogator (Table 5-9) provides continuous monitoring, rapidly updating temperature profiles along the length of the completions.

Table 5-9 – SureVIEW DTS Surface Interrogator Specifications

Description	Value
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW DAS

The SureVIEW DAS interrogator offers all the benefits of fiber-optic acoustic monitoring—from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring, combined in a single interrogator (specifications shown in Table 5-10).

Table 5-10 – SureVIEW DAS VSP Specifications

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με

SureVIEW WIRE

The SureVIEW WIRE structural-integrity management system enables high-density strain monitoring of the wellbore and surrounding formation to detect, localize, and classify issues with reservoir compaction, shearing, and well integrity. The cable is deployed along the outside of the casing in the well, where it is cemented into place and brought online. Once online, data can be closely observed across the entire geological interface. An illustration of this technology is shown in Figure 5-18, and the technical specifications are provided in Table 5-11.

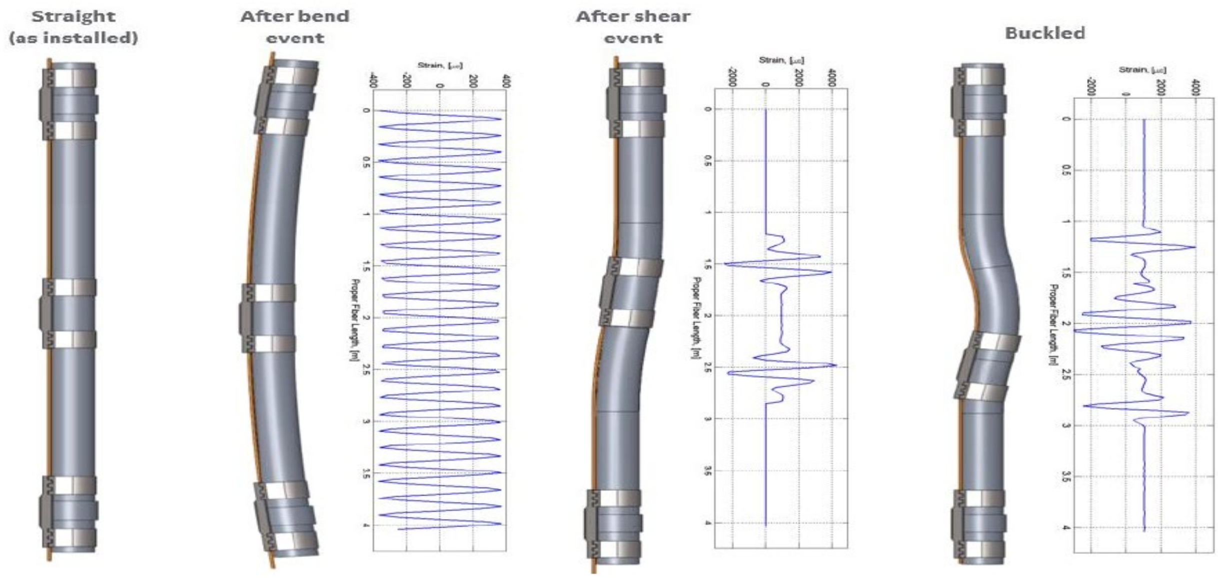

Figure 5-18 – SureVIEW WIRE Well Integrity Evaluation

Table 5-11 – SureVIEW WIRE Cable Specifications

SureVIEW™ WIRE Cable	
Specifications	

Low Temperature Cable	• 1/4" OD
	• 0.035" Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 120 Deg C Temperature Rating
	• 15,000 psi Pressure Rating

High Temperature	• 1/4" OD
	• 0.035" Wall
	• Alloy 825
	• Specialty Bragg Grating Fibers
	  • One fiber configuration for Axial Strain Only
	  • Two fiber configuration for Axial and Curvature
	• 300m Max Sensor Length*
	• 225 Deg C Temperature Rating
	• 15,000 psi 15,000 psi Pressure Rating

**may require multiple cables spliced to achieve desired length*

<u>Tubing Encapsulated Conductor</u>

TEC is a proven technology that the oil and gas industry has used reliably for more than 25 years. The TEC is installed to electrically support the QPT Elite gauges and is designed for prolonged life in the most hostile downhole environments. The TEC's primary function is to transmit both electronic digital signals and power between subsurface components and a surface interface module used for reservoir management. The BHGE-standard TEC product is a 0.25-in. OD tubing-armor cable, which includes an insulated 16-American wire gauge (awg) solid conductor. The armor is a metal-clad CRA tube containing filler materials that centralize the core. An encapsulation material specially designed with safe removal components is recommended to be extruded over the TEC, thereby adding to the metal sheath a layer of protection from abrasion while running downhole. Figure 5-19 illustrates the design of the TEC, and the technical specifications are listed in Tables 5-12 and 5-13.

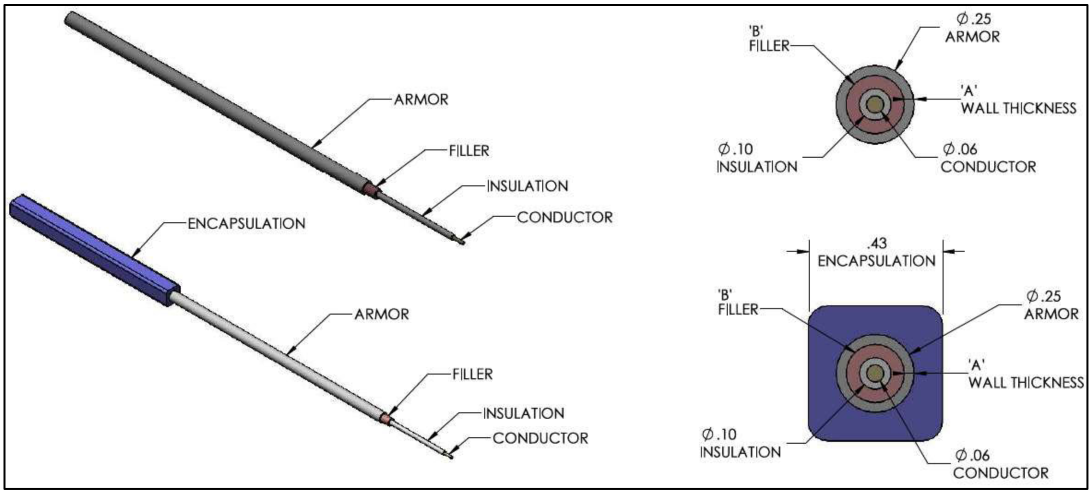

Figure 5-19 – Tubing Encapsulated Conductor

Table 5-12 – TEC Specifications, Part I

Description	Value	
Size 0.035-in. Wall TEC		
Materials	316L stainless UNS S31603	Alloy 825 UNS N08825
Weight	198 kg/km (133 lb/1,000 ft)	199 kg/km (135 lb/1,000 ft)
Armor resistance at 20°C	51.2 Ohms/km (15.6 Ohms/1,000 ft)	73.9 Ohms/km (22.5 Ohms/1,000 ft)
Capacitance at 20°C	98 pF/m	
Collapse pressure rating (psi)*	30,000	

Table 5-13 – TEC Specifications, Part II

Wall (in.)	Alloy	Tensile (psi)				Yield (psi)			
		Minimum	Maximum	Average	STD	Minimum	Maximum	Average	STD
0.035	316L	122,000	178,000	153,000	6,800	100,000	158,000	125,000	8,200
0.049		141,000	154,000	145,000	5,100	113,000	130,000	119,000	6,400
0.035	A825	123,000	182,000	144,000	8,400	108,000	150,000	126,000	7,100
0.049		113,000	157,000	139,000	7,300	89,000	139,000	122,000	7,500

SureSENS QPT Elite Gauge

The reliable, accurate SureSENS QPT Elite gauge (Figure 5-20) measures static and dynamic pressures and temperatures. The highly robust gauge ensures mechanical integrity by deep penetration and high-vacuum, electron-beam fusion welds without filling material. Only two fittings (the pressure port and the TEC) are required to interface the gauge with the carrier. The fittings can be externally tested in the direction that they will experience pressure, eliminating the need for an internal pressure test tool.

Figure 5-20 – SureSENS QPT Elite Gauge

QPT Elite Pressure Interface – Pressure Testable Manifold

The gauge-pressure interface connection to the carrier is through a pressure-testable manifold interface attached to the mandrel. Triple metal-seal rings are pressure tested to ensure integrity before deployment. The three metal seals provide redundant metal-to-metal sealing, tested in the same direction as the applied pressure in the final installation. This sealing provides a true, unique metal-to-metal design that is bidirectional and dual-testable. Figure 5-21 illustrates the design, and Table 5-14 lists the technical specifications.

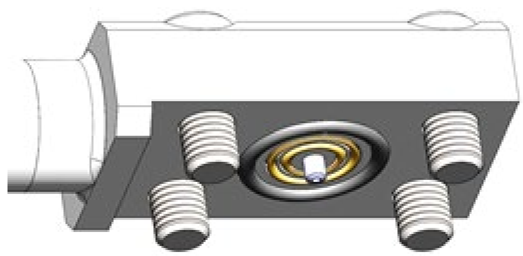

Figure 5-21 – External Sensor

Table 5-14 – QPT Elite Pressure Interface – Pressure-Test Manifold Specifications

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	16,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 16,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

<u>SureSENS QPT Gauge Carriers</u>

The carrier body is machined from a single bar stock without welding or heat-treating processes (Figure 5-22). The gauge assembly is installed into a recessed pocket in the carrier, protecting the gauge without needing a cover plate. The uphole end of the gauge is secured to the carrier by a clamp, which is fastened to the carrier by socket head screws. All tubular completion products are designed to meet or exceed the tubing/casing specifications supplied by the customer. All tubular products are also inspected and tested per American Petroleum Institute (API) 5CT requirements for drift and pressure.

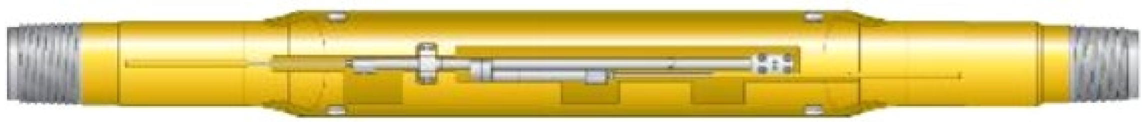

Figure 5-22 – SureSENS QPT Gauge Carrier Illustration

Steel Blast Protectors

The blast protectors are installed above and below each zone over the fiber and TEC lines. The protectors have round steel bars that run the length of and are welded into the channel on both sides of the cables—to increase magnetic mass/signature for detection by the High-Resolution Vertilog (HRVRT) tool, to position the guns away from the cables (Figure 5-23).

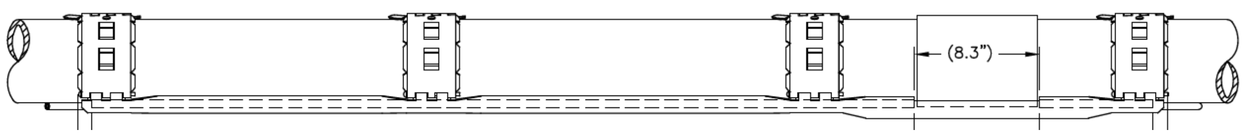

Figure 5-23 – Steel Blast Protector Illustration

Cross-Coupling Protectors

To protect the downhole cable, cross-coupling cable protectors (Figure 5-24) are mounted at each tubing joint coupling to protect the cable transitions across the coupling. A potential exists for the downhole cable to be damaged because of abrasion or crushing between the tubing and casing internal wall during the installation process, thereby resulting in the loss of functionality of the associated downhole equipment.

Figure 5-24 – Cross Coupling Protector

5.5.10 VSP Monitoring Conclusion

Using the VSP method to quantify CO_2 plume development over time has been demonstrated in several cases worldwide. Using this data ensures that implementing this method in a time-lapse format will produce an image of the plume extent and its future development. Also, the use of VSP in the injection wells—using a permanently installed fiber optic sensor—will produce an image centered on the injection spot with a higher resolution than that of a traditional wireline deployed geophone array. Moreover, VSP eliminates the need to create additional penetrations in the ACZ for monitoring purposes.

The fiber optic set-up installed in these wells will also allow for ease of pressure and temperature monitoring in all sections of the wells, the data from which will be used in direct calculations of the pressure plume.

Finally, and most importantly, this VSP system, along with the direct plume calculations, will allow for monitoring the plume migration without the need to create additional artificial penetrations—which could inadvertently form a conduit out of the confinement intervals. Additionally, this approach minimizes the environmental impact of disturbing surrounding wetland areas.

5.6 <u>Conclusion</u>

Monitoring the injection wells and tracking the CO_2 plume and pressure front are key components to the successful sequestration of CO_2 for the Titan Project. Titan is committed to ensuring that best testing and monitoring practices are employed throughout the lifecycle of this project.

Appendix F – Testing and Monitoring:

- Appendix F-1 USDW and AZM Monitoring Well Plan Map
- Appendix F-2 TCS WM No. 1 Schematic
- Appendix F-3 TCS WM No. 2 Schematic
- Appendix F-4 Atlas No. 1 Schematic
- Appendix F-5 Andes No. 1 Schematic

5.7 References

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