SECTION 5 – TESTING AND MONITORING PLAN

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5.1 Introduction

This section includes the proposed testing and monitoring plans for the White Castle Injection Wells (WC IW-B) No. 001 and No. 002 carbon capture and sequestration (CCS) wells [redacted] 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 Testing and Monitoring Plan, as explained in detail below, will begin operating before CO_2 injection commences. 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 pre-determined timeline based on carbon front growth and well conditions at the time of injection cessation. Included here as well is the monitoring strategy for the injection stream, well operating conditions, downhole parameters, Underground Sources of Drinking Water (USDWs), above-zone confinement, and carbon front growth.

5.2 Reporting Requirements

In compliance with SWO 29-N-6 **§3629.A** [40 CFR **§146.91**] requirements, Harvest Bend CCS LLC (Harvest Bend CCS) will provide routine reports to the Underground Injection Control (UIC) Program Director (UIC Director). The contents of those reports and their submittal frequencies are described below:

- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 5 working days of the 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
    - Written Notification – Reported within 5 working days of the event
- Any failure to maintain mechanical integrity
    - Verbal Notification – Reported within 24 hours of event
    - Written Notification – Reported within 5 working days of the event
- 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 5 working days of 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 event
    - Written Notification – Reported within 5 working days of event

Quarterly Reports:

- Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data or parameters
- 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 volume of total annulus fluid and any annulus fluid added
- Results of any monitoring as described in this section

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

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

Harvest Bend CCS will submit all reports, submittals, and notifications to both the Environmental Protection Agency (EPA) and the Louisiana Department of Natural Resources (LDNR), and ensure that all records are retained throughout the life of the project. Per SWO 29-N-6 **§3629.A.6** [40 CFR **§146.91(f)**], records will be retained for 10 years after site closure. Additionally, injected fluid data, including nature and composition, will also be retained for 10 years following site closure—and, after the retention period, can be delivered to the UIC Director upon request. Monitoring data will be retained for 10 years post-collection, while well-plugging reports, post-injection site care data, and the site closure report will be retained for 10 years after site closure.

5.3 Testing Plan Review and Updates

Per 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 least every 5 years to incorporate collected monitoring and operational data, and the most recent area of review (AOR) reevaluation. 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 required by the UIC Director.

5.4 Testing Strategies

5.4.1 Minifrac Test

To measure the fracture gradient of the confining and injection zones [redacted] Harvest Bend CCS proposes conducting multiple "minifrac" tests during the open-hole logging program on WC IW-B No. 002. [redacted]. Minifrac testing serves to fulfill requirements in SWO 29-N-6 **§3617.B.4.a** [40 CFR **§146.87(d)(1)**] and provides an alternative to the injectivity test requirement from SWO 29-N-6 **§3617.B.5.c** [40 CFR **§146.87(e)(3)**], which could potentially put a larger frac on the injection sands and confining interval.

5.4.1.1 <u>Testing Method</u>

The minifrac tests will be conducted using a formation pressure and sampling tool, with parameters such as tensile fracturing pressure, stress direction, far-field minimum and maximum stress, and tensile strength. Zonal isolation will be achieved [redacted]. The program will be designed so that the fracture will propagate into the formation on the order of tens of feet, but fracture height will not exceed the distance between the packers. After running filtration tests, borehole fluid will be pumped against the formation at a constant rate until a fracture is created. Once the fracture has been initiated, the pump will be stopped, and both the instantaneous shut-in pressure and subsequent pressure decline will be measured.

Several injection and flowback tests will be performed. Capturing this data in four to five test cycles will reduce the uncertainty and capture a better measure of the far-field minimum stress. The data will be paired with dual oil-based, mud-imaging tools to give information regarding the maximum and minimum stress directions.

5.4.2 Chemical Composition Confirmation Testing

Under SWO 29-N-6 **§3625.A.1** [40 CFR **§146.90(a)**] requirements, Harvest Bend CCS will acquire samples of the CO_2 injection stream and evaluate any potential interactions of carbon dioxide and other injectate components. CO_2 injection stream samples will be taken quarterly for chemical analysis of the parameters listed in Table 5-1, in addition to continuous pressure and temperature analysis.

5.4.2.1 <u>Sampling Methods</u>

Carbon dioxide stream samples will be collected from the CO_2 pipeline in a location where the injection conditions are representative. A sampling station will be connected to the pipeline at a sampling manifold, and sample cylinders will be purged with the injectate gas—to expel laboratory-added gas and confirm a quality sample collection.

5.4.2.2 <u>Parameters Measured</u>

Table 5-1 – Injectivity Test Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
pH	Quarterly
CO_2 (%)	Quarterly
Water (lb/MMscf)	Quarterly
Oxygen (%)	Quarterly
Sulfur (ppm)	Quarterly
Methane (%)	Quarterly
Ethane (%)	Quarterly
Other Hydrocarbons (%)	Quarterly
Hydrogen Sulfide (ppm)	Quarterly
Benzene (%)	Quarterly

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

5.4.3 Mechanical Integrity Testing – Annulus Pressure Test

In accordance with SWO 29-N-6 **§3627.A.2** [40 CFR **§146.89(b)**], Harvest Bend CCS will ensure mechanical integrity by performing annular pressure tests after the wells have been completed, prior to the start of injection, and after any workover operation involving the removal and replacement of the tubing and packer.

The annular pressure tests should 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) fluid pressure, then using a block valve 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 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 that 30-minute minimum duration.

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

5.4.4 External Mechanical Integrity Testing

In adherence to the requirements of SWO 29-N-6 **§3627.A.3** [40 CFR **§146.89(c)**], Harvest Bend CCS will perform an annual external mechanical integrity test (MIT) by conducting a temperature log [redacted]. A temperature log [redacted] will be run in each well before initiating injection operations, to establish a baseline against which future logs can be compared. The wells will be shut in for a duration of approximately 36 hours prior to running the temperature logs, to allow temperatures to stabilize. Satisfactory mechanical integrity is demonstrated by proper correlation between the baseline and subsequent logs.

All temperature logs [redacted] recorded during the MIT will be submitted to the Injection and Mining Division within 30 days of log-run completion.

5.4.5 Pressure Falloff Testing

Harvest Bend CCS will perform a required pressure falloff test on each well every 5 years per SWO 29-N-6 **§3625.A.6** [40 CFR **§146.90(f)**]. The tests will measure near-wellbore formation properties and monitor for near-wellbore environmental changes that may impact injectivity and result in pressure increases.

5.4.5.1 Testing Method

The injection rate and pressure will be held as constant as possible prior to the beginning of the test, and continuous data will be recorded during testing. Once the well has been shut in, continuous pressure measurements will be taken via a downhole gauge. The falloff 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.

5.4.5.2 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 via analysis of observed pressure changes and/or pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions can be exposed by the comparison of pressure falloff tests prior to initial injection, with later tests. The effects of two-phase flow effects will also be considered. Such well parameters resulting from falloff testing will be compared against those used in AOR determination and site computational modeling. Notable changes in reservoir properties outside the range of modelled uncertainties may dictate that an AOR reevaluation is necessary.

All pressure falloff test results will be submitted to the Injection and Mining Division within 30 days of test completion.

5.4.5.3 Quality Assurance/Control (QA/QC)

All field equipment will undergo inspection and testing prior to operation. Manufacturer calibration recommendations will be adhered to during the use of pressure gauges in the falloff test. Documentation certifying proper calibration will also be enclosed with the test results.

5.4.6 Continuous Injection Stream Monitoring

Harvest Bend CCS will ensure that continuous monitoring of the injection pressure, rate and volume, and annulus pressure comply with SWO 29-N-6 **§3625.A.2** [40 CFR **§146.90(b)**] requirements. A Supervisory Control and Data Acquisition (SCADA) system will be installed [redacted] to facilitate the operational data collection, monitoring, recording, and reporting for each injection well.

Continuous monitoring of the injected CO_2 stream pressure and temperature will be performed, using digital pressure gauges installed in the CO_2 pipeline near the pipeline-wellhead interface. An on-site SCADA system will be connected to the pipeline, and a flow meter—used to measure the injected CO_2 mass flow rate—will be installed upstream of the injection wells. The mass flow rate meter will be connected to the SCADA system at the CO_2 storage site to ensure continuous monitoring and control of the CO_2 injection rate.

Downhole annular and tubing pressures will be monitored via downhole pressure gauges run on a fiber-optic-cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained. The package will include distributed temperature sensing (DTS) technology to support continuous temperature monitoring capabilities. *Section 5.5.5* provides more detail on this equipment.

Figure 5-1 provides an illustration of the control and monitoring systems to be installed at [redacted] injection wells.

[redacted]

Figure 5-1 – Typical Injection Well and Injection Skid Flow Schematic

5.4.6.1 Analytical Methods

Harvest Bend CCS will review and interpret continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination for trends to help determine any need for equipment maintenance or calibration. Quarterly reports on the monitoring data will also be submitted.

Per SWO 29-N-6 **§3621.A.7.a.i** [40 CFR **§146.88(e)(2)]**, automatic shut-off systems and alarms will be installed to alert the operator and shut in the well when operating parameters such as annulus pressure, injection rate, etc., diverge from permitted ranges or gradients.

5.4.7 Cement Evaluation and Casing Inspection Logs

Per SWO 29-N-6 **§3617.B.1.c.ii** [40 CFR **§146.87(a)(3)(ii)**] and SWO 29-6-N **§3617.B.1.d.iv** [40 CFR **§146.87(a)(4)(iv)**], at the time of initial well completion a comprehensive cased-hole logging suite will be run on the production casing string for each well. This suite of logs will include a radial cement bond log with variable density and temperature tracks. Additional baseline logs will include [redacted] to establish the condition of the casing. This survey will characterize the original state of the wellbore materials. [redacted] This survey will serve as the baseline survey for future casing inspection efforts.

Casing inspection logs will be performed every 5 years, using a combination of conventional casing inspection logs and [redacted] surveys. The tools that will be run at that time include:

[redacted]

5.4.8 Logging and Testing Reporting

A report that includes log and test results obtained during the drilling and construction of WC IW-B No. 001 and No. 002, and interpretated by a knowledgeable log analyst, will be submitted to the UIC Director as per SWO 29-N-6 **§3617.B.1** [40 CFR **§146.87(a)**].

5.5 <u>Monitoring Programs</u>

5.5.1 Corrosion Coupon Monitoring

Monitoring corrosion of the wells' 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 Harvest Bend CCS, will be performed in addition to the examination of casing inspection logs conducted every 5 years, with permit renewal. This evaluation will ensure that the well components meet the minimum standards for material strength and performance.

5.5.1.1 Sampling Methods

Corrosion coupons, comprising the same material as the injection tubing and production casing, will be placed in the carbon dioxide injection-flow stream. They 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.

5.5.2 Groundwater Quality Monitoring

In order to meet SWO 29-N-6 **§3625.A.4** [40 CFR **§146.90(d**] requirements, groundwater quality and geomechanical monitoring will be conducted above the confining zone to detect potential changes that could result from fluid leakage from the injection zone. Due to the lack of artificial penetrations and shallow-cutting faults in the AOR, Harvest Bend CCS will utilize [redacted] groundwater monitoring well [redacted] as shown in Figure 5-2. [redacted] WC GW-A No. 001 [redacted] and WC GW-B No. 001 [redacted] perforating into the lowermost USDW sand formation. WC GW-B No. 001 will be drilled and analysis performed on baseline samples prior to injection in WC IW-B No. 001 and No. 002 [redacted]. Then, water samples will be collected and tested quarterly from this depth to monitor for signs of CO_2 leakage.

Figure 5-2 (*Appendix F-1*) displays the well locations, which are also listed in Table 5-3.

[redacted]

Figure 5-2 – Monitoring Wells Plan

The evaluation of well logs for four nearby wells has indicated the base of the USDW to be at approximately [redacted] below surface, near the proposed injection wells. Water samples will be collected at this depth to monitor for signs of CO_2 leakage. These four wells (Table 5-2; *Appendix C-2*) are located within [redacted] of the proposed WC IW-B No. 001 and No. 002.

Table 5-2 – Nearby Wells for USDW Determination
(Arranged in increasing distance from injector)

	API Number	Serial Number	Depth of USDW (ft)	Distance from WC IW-B No. 001 (ft)	Distance from WC IW-B No. 002 (ft)
1	[redacted]				
2					
3					
4					

The monitoring well locations (Table 5-3) were selected to minimize surface impact and at a location down-gradient of the regional water flow.

Table 5-3 – Groundwater Monitoring Well Locations

Monitoring Well Location Info	WC GW-A No. 001	WC GW-B No. 001
Latitude	[redacted]	
Longitude		
Datum		
Total Depth		

5.5.2.1 Parameters Measured

Table 5-4 – Groundwater Quality Parameters Measured and Measurement Frequency

Parameter/Analyte	Frequency
Aqueous and pure-phase CO_2	Quarterly
TDS	Quarterly
pH	Quarterly
Specific conductivity (SC)	Quarterly
Density	Quarterly
Other parameters including major anions and cations, trace metals, hydrocarbons, and volatile organic compounds	Quarterly

5.5.2.2 Sampling Methods

Fluid samples will be acquired quarterly from the groundwater monitoring well. The sampling methodology will ensure that all samples represent current USDW fluid properties. Water samples will be collected per procedures from the Injection and Mining Division's state-approved laboratories.

5.5.2.3 Analytical Methods

Harvest Bend CCS will test water samples and maintain results for the parameters listed in Table 5-4. If results indicate the existence of impurities in the injectate, groundwater samples should also be tested to flag any concentrations exceeding the baseline. Testing results will be stored in an electronic database.

Observation of the following trends may be detection of signs that fluid may be leaking from the injection interval(s):

- Change in total dissolved solids (TDS)

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

5.5.2.4 Laboratory to be Used/Chain of Custody Procedures

Water samples will be submitted to the Injection and Mining Division via a state-approved laboratory. Harvest Bend CCS will observe standard chain-of-custody procedures as well as maintain records, to allow full reconstruction of the sampling procedure and storage and transportation, including problems encountered.

5.5.2.5 Quality Assurance and Surveillance Measures

Harvest Bend CCS will collect duplicate samples and trip blanks for QA/QC purposes. These will be used to validate test results and ensure that samples have not been contaminated.

5.5.2.6 Plan for Guaranteeing Access to All Monitoring Locations

The surface-use lease agreement with the landowner authorizes the installation of groundwater monitoring wells in locations that ensure access to them for sampling and maintenance purposes. The operator will have full-time access to the USDW monitoring well location. Unauthorized access will be prevented by capping and locking out the well.

5.5.2.7 Additional Freshwater Baseline Sampling

Prior to first injection, Harvest Bend CCS will collect baseline freshwater samples from several active water wells in close proximity to the White Castle Project area. To the extent that Harvest Bend CCS can obtain approval from the well owners, the closest active freshwater wells to the currently predicted carbon front extent will be sampled. Water samples will be collected per procedures from the Injection and Mining Division's state-approved laboratories, one of which will perform baseline analysis to measure the same parameters discussed in *Section 5.5.3.1*. These baseline analyses will serve for comparison against subsequent samples collected after first injection, should the need arise. All active freshwater wells near the White Castle Project area are shown in *Appendix C-4*.

5.5.3 Upper Confining Interval Monitoring

Similar to the groundwater monitoring strategy, Harvest Bend CCS will utilize [redacted] upper confining interval (UCI) or "above-zone" monitoring well [redacted] as shown in Figure 5-2 (*Appendix F-1*). The WC AZMW-B No. 001 will be drilled near the subject injection wells, [redacted] in the White Castle Project area, for above-zone monitoring purposes. Conceptual well-construction plans are included in *Section 4*. This well will continuously monitor the pressure of the first mappable sand identified above the UCI. The well will be completed around [redacted] formation. Any deviations from baseline pressures will initiate additional investigations in the area. If necessary, fluid samples can be obtained from this well to compare against baseline samples, collected and tested when the well is completed.

5.5.4 Carbon Front and Critical Pressure Monitoring

Harvest Bend CCS proposes a two-tiered system to be used for carbon and pressure front tracking per the operational monitoring requirements of SWO 29-N-6 **§3625.A.7** [40 CFR **§146.90(g)**]. Carbon front calculations based on continuously recorded pressures and temperatures will be used as a direct monitoring approach, while a phased, time-lapse seismic-surveying approach will be used to monitor the carbon front indirectly.

- Direct method: rate transient analysis from measured parameters
- Indirect method: time-lapse seismic surveying

This two-tiered system, detailed further below, will serve two purposes: first, to verify reservoir conditions during injection; second, to track carbon front migration and validate the carbon front model. Continuous pressure and temperature monitoring of the injection reservoir will allow for continuous monitoring of reservoir conditions and calculations. To confirm that the carbon front is developing as expected, a phased carbon front-monitoring approach will be utilized. Initially, carbon front growth will be monitored with time-lapse 2D surveys. [redacted] Seismic surveys will be run, minimally, every 5 years to monitor carbon front growth.

Additionally, Harvest Bend CCS also plans to drill a stratigraphic test ("strat") well approximately [redacted]

5.5.4.1 Direct Monitoring: Rate Transient Analysis

Rate transient analysis using known reservoir characteristics will allow for the calculation of more complex parameters within each injection interval. By using proven and industry-standard flow equations to suit CO_2 injection, the extent of the carbon front can be determined. Direct monitoring, to satisfy requirements specified in SWO 29-N-6 **§3625.A.7.a** [40 CFR **§146.90(g)(1)**], will be based on continuous pressure, temperature, and injection rate data to verify and refine modeling efforts, ensure that the backflow of CO_2 does not occur, and prevent USDW contamination.

The reservoir model built during the site evaluation and permitting phase of the project may be further used to predictively monitor the reservoir conditions during injection operations. Through reservoir engineering and transient flow analyses, the model may be updated with actual temperature, pressure, and rate injection data, to evaluate the injection stream's effect on reservoir conditions and so derive accurate reservoir conditions.

Additionally, any periods of shut-in can be observed and evaluated as a drawdown test. To do this, the shut-in wellhead pressure, downhole tubing pressure, and temperature readings will be recorded and used for pressure transient analysis of the reservoir. Results of the analysis will include the radius and magnitude of pressure buildup and reservoir performance characteristics, such as permeability and transmissibility. Analysis results will then be used to confirm and adjust the previously constructed models.

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

5.5.4.2 Indirect Monitoring: Time-Lapse Seismic Surveying

Harvest Bend CCS will use time-lapse seismic technology as the first method to monitor the carbon front and development in order to meet the operation monitoring requirements specified in SWO 29-N-6 **§3625.A.7.b** [40 CFR **§146.90(g)(2)**].

Reservoir monitoring using time-lapse seismic 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 the contrast in compressional velocity between high CO_2 concentrations and formation fluids. As formation fluids are displaced by CO_2, the change in acoustic impedance during carbon front growth can be mapped.

Time-lapse seismic monitoring is proposed for the White Castle Project to:

- Monitor the CO_2 injection to ensure the CO_2 propagation within the storage reservoir is as intended,
- Confirm there is no leakage of CO_2 through the upper confining interval, and
- Confirm long-term carbon front stability after injection.

The work steps involved in a time-lapse seismic monitoring program include:

1. Rock Physics Model
2. Seismic Monitoring Feasibility
    a. 1D synthetic model with brine-filled reservoir
    b. 1D model with fractional CO_2-filled reservoir
3. Baseline Surveys
4. Seismic Monitoring
    a. Repeat/time-lapse 2D surface seismic survey
    b. Repeat/time-lapse 3D surface seismic survey, if needed

Rock Physics Model

The first step in seismic monitoring of CO_2 injection is to create a locally calibrated rock physics model. The model is used to predict the seismic response of the reservoir following injection of CO_2 and to design a seismic monitoring program that is optimized for the project.

Deterministic petrophysical analysis estimations, predominantly from local wireline data, are used to forecast the dry mineral rock components from the in situ (in this case, brine) response prior to saturation modeling. The model uses rock properties such as:

- Total porosity
- Effective porosity
- Water saturation
- Clay (type)
- Quartz
- Mineral content

For the White Castle Project, the initial rock physics model was evaluated with Paradigm Geophysical's wireline log evaluation tools, part of their Paradigm-19 software package. [redacted] The analog reservoir properties were taken from wireline logs from the nearby [redacted] well, for which both sonic and density logs are available (Figure 5-3). [redacted].

[redacted]

Figure 5-3 – [redacted] Log Analysis

Based on those wireline logs, the in-situ brine-filled sand is expected to have an effective porosity of [redacted] and a corresponding bulk density of [redacted] gm/cc. Sonic log response is [redacted] μsec/ft, which corresponds to compressional velocity of [redacted] ft/sec. The corresponding values for the adjacent shales were measured to be [redacted] gm/cc and [redacted] ft/sec.

For seismic elastic modeling, three elastic parameters are required, typically represented by density (ρ), compressional velocity (Vp) and shear velocity (Vs). Shear velocity is usually more difficult to determine than the other two parameters because relatively few wireline shear sonic logs are recorded. Fortunately, with respect to the White Castle Project area, there is a nearby well, [redacted] with a shear sonic log over the depth range of interest. The wireline Vp/Vs was cross-plotted against gamma-ray for that well (Figure 5-4) and observed that the clean sands (e.g., low gamma ray values around 20) have a Vp/Vs ratio of about 2.0, whereas shales (e.g., high gamma ray values around 100) have a Vp/Vs ratio of about 2.5. This linear Vp/Vs trend was applied to the observed gamma ray values and compressional velocities for the [redacted] well, to derive corresponding shear velocities for clean sand ([redacted] ft/s) and shale ([redacted] ft/s) for our rock physics model.

[redacted]

Figure 5-4 – Vp/Vs vs. Gamma Ray in the [redacted]

The trio of elastic properties for the clean sand were then used for a starting condition (brine case) for Gassmann fluid substitution. Physical properties in the reservoir at [redacted] depth are shown in Table 5-5. Reservoir temperature and pressure were derived from local gradients. Brine salinity is known from local resistivity to be approximately [redacted] ppm.

Table 5-5 – Physical Properties for [redacted] CO_2 Injection

Physical Property	Value
[redacted]	

The salinity, pressure and temperature, assumed to be [redacted], respectively, are used as inputs to determine brine compressional velocity and density using industry-standard empirical relationships (Batzle & Wang, 1992) that are encoded in a fluid property calculator in Paradigm's software (Table 5-6). From brine Vp and ρ, the brine's fluid bulk modulus (K) was calculated to be [redacted] MPa (SI units) at reservoir conditions. Similarly, the fluid properties for 100% CO_2 at reservoir conditions were calculated using the National Institute of Standards and Technology's (NIST) online web calculator. At reservoir conditions the CO_2 is a supercritical fluid with a bulk modulus of [redacted] MPa.

Table 5-6 – Fluid Acoustic Properties for [redacted] CO_2 Injection

Fluid Acoustic Properties for [redacted] CO_2 Injection		
Property	**Brine**	**CO_2**
[redacted]		

By using the known elastic properties of the brine-saturated clean sand, the so-called "dry rock" bulk modulus of the sand without any fluids can be calculated. The dry bulk-modulus is then used as an input to the Gassmann fluid substitution Equation 1 (Figure 5-5) to calculate the bulk modulus for different saturations of CO_2 in the clean sand.

$$K_{sat} = K_{frame} + \frac{\left(1 - \frac{K_{frame}}{K_{mineral}}\right)^2}{\frac{\varphi}{K_{fl}} + \frac{1-\varphi}{K_{mineral}} - \frac{K_{frame}}{K_{mineral}^2}} \quad \text{(Eq. 1)}$$

Figure 5-5 – Gassmann Fluid Substitution Equation

The results of those calculations are shown in Table 5-7 with Vp, Vs, and ρ of the CO_2-saturated sand, along with several other corresponding elastic properties.

Table 5-7 – Elastic Rock Properties from Gassmann Fluid Substitution

Clean Sand Reservoir Model												
	Sw	DT	DTS	ρ	Vp	Vs	Vp/Vs	K	λρ	μρ	Pimp	Simp
shale	[redacted]											
wet sand												
CO_2 sand												
CO_2 sand												

Petro-Elastic Model

The rock physics model will generate a zero-order dry rock model, which will then be used to establish a petro-elastic model (PEM) by perturbing the elastic parameters for varying degrees of saturation. Figure 5-6 illustrates the combination of the rock physics model (in red) and the PEM at [redacted] water saturation (blue). Changes in saturation result in changes primarily to the compressional wave velocity for this type of rock. The effect of gas replacement of the reservoir fluid can be estimated using both the fluid saturation and fluid replacement from the rock physics model.

[redacted]

Figure 5-6 – Application of Petro-Elastic Model to Rock Physics Model

Prediction of velocity and density as functions of injectate saturation is the final result of the PEM. The seismic response measured by seismic surveys can be determined using the acoustic impedance calculated from both of those elastic properties (Figure 5-7).

[redacted]

Figure 5-7 – Petro-Elastic Model Predictions of Velocity and Density as a Function of Saturation

Seismic Monitoring Feasibility

With the elastic properties determined for the CO_2 injected sand, the changes in reflectivity of the CO_2 sand versus the original brine sand can be modeled via Zoeppritz seismic modelling (Aki & Richards, 1980). This is done in two ways. The first is an idealized amplitude-versus-angle (AVO) plot for a single shale-on-sand interface. The second is a synthetic angle gather showing the expected seismic response of the sands, using a real-world, band-limited wavelet and well logs from the [redacted] well.

Results of the single-interface AVO curve analysis are shown in Figure 5-7. The response of the clean, brine-filled sand is seen to be a simple Class III AVO (Rutherford & Williams, 1989), as commonly seen for clean sands in the Gulf Coast at this depth. [redacted]

[redacted]

[redacted]

Figure 5-8 – Seismic Zoeppritz Modeling Results

A more realistic seismic model can be created using the elastic logs from the [redacted] well, convolved with a real-world wavelet extracted from the White Castle Project–area 3D seismic volume. The logs are first modeled with their original wet fluids in the [redacted] blocky sand. The model is then repeated, substituting the reservoir properties for the [redacted] CO_2-saturated sand. The model uses an [redacted], which closely matches the seismic spectrum observed in the White Castle Project–area 3D seismic volume, at the two-way time corresponding to reservoir depths. The input logs and output synthetic angle gather are shown in Figure 5-9A.

[redacted]

Figure 5-9 – [redacted] Sand AVO Model with CO_2 Fluid Substitution in the [redacted]

The results of the AVO modeling (Figure 5-9B) using CO_2 injection into the [redacted] sand in the [redacted] confirm the results seen from the simple single-interface model. There is a large increase in seismic amplitude, [redacted], from the wet reservoir case to the CO_2-saturated case. The CO_2 saturated case also has a much stronger Class III AVO, as measured from the trough associated with the top of the reservoir. For this particular sand, the bottom of the reservoir—a peak—could also be easily mapped, giving similar results but with opposite polarity.

By modifying this elastic seismic model with differing saturations of the injectate, expected amplitude of the resulting seismic stacks can be plotted against CO_2 saturation. [redacted]

[redacted]

[redacted]

Figure 5-10 – Seismic Stack Response vs. Fractional CO_2 Saturation

<u>Baseline Surveys</u>

The primary seismic monitoring method will be time-lapse 2D seismic surveys. To ensure that an accurate time-lapse response can be calculated, a baseline 2D survey will be acquired prior to the start of injection. The baseline 2D survey will extend beyond the limits of ultimate carbon front to ensure that the edge of the carbon front can be confirmed in all directions. [redacted] Figure 5-11 displays an example of the proposed 2D seismic baseline that will be acquired prior to injection. The final grid layout is subject to detailed surveying, permitting, and alignment with the seismic contractor. The advantage of utilizing 2D for monitoring is that the results of the monitoring will be available quickly, and along the 2D lines the resolution of the reservoir will be higher than of a standard 3D seismic survey acquired in this type of environment. Because the entire storage site is flooded timber with a high amount of vegetation and wildlife, 2D surveys will also require less clearance and impart a lower environmental impact on the area. Harvest Bend CCS does recognize that in some instances a full 3D view of the storage site may be required. Our studies have indicated that the strong time-lapse response allows us to utilize existing 3D surveys as a baseline; these surveys will be reprocessed as a 3D baseline if necessary.

[redacted]

Figure 5-11 – Proposed 2D Seismic Baseline

Seismic Monitoring

Seismic surveys will be run, at least, every 5 years to monitor carbon front growth. An example of the output from time-lapse seismic monitoring is shown in Figure 5-12[1].

[1] https://csegrecorder.com/articles/view/using-a-walk-away-das-time-lapse-vsp-for-co2-sub-plume-monitoring

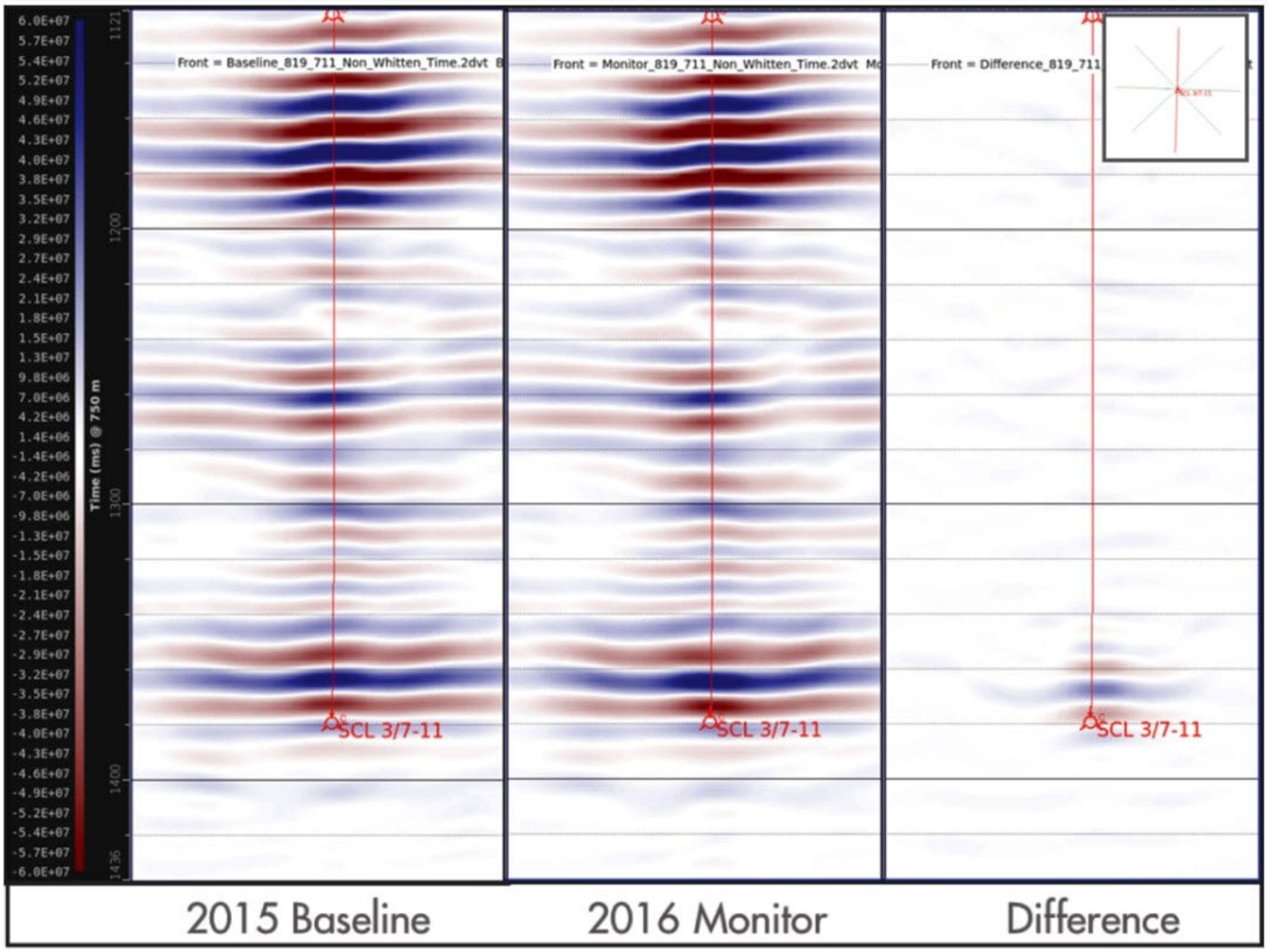

Figure 5-12 – Baseline and Subsequent VSP

The seismic monitoring will take advantage of the fact that the carbon front will expand away from the injection wells [redacted]

2D Surface Seismic

The baseline 2D survey will be repeated periodically to track the movement of CO_2 through the reservoir. These 2D lines have been designed [redacted], which gives much denser coverage closer to the injection wells, allowing for detailed analysis of the behavior and migration of CO_2 through the reservoir. The development plan of recompletion of multiple stages (creating stacked carbon fronts) means that this close-by dense coverage will continue to be useful throughout the project, as shallower injection stages are developed.

Vertical Seismic Profiles

One option under consideration is to record offset vertical seismic profiles (VSPs) via distributed acoustic sensing (DAS) fiber optic cable permanently installed in the injection well(s). VSP data can be acquired at the same time as the 2D lines; thereby "piggybacking" on the same source points as simultaneously used for the 2D surface-seismic lines. The resulting time-lapse VSP surveys would be used for additional imaging of those injection reservoir levels in which the carbon front is still relatively close to the injection well, and will be a useful calibration for the 2D time-lapse seismic response.

3D Surface Seismic

Time-lapse 3D surveys can be acquired, if necessary, [redacted]. The conformance of the dynamic reservoir model will be evaluated throughout the project, and if there are significant deviations from the model this tool may be deployed to help reduce uncertainty.

5.5.5 Monitoring Equipment and Setup

This section details proposed equipment to be utilized in periodic survey and downhole pressure and temperature monitoring operations to determine the carbon front growth over time.

5.5.5.1 Seismic Survey Acquisition

Surface seismic acquisition for carbon front monitoring will use dynamite shot holes for seismic source and independent node receivers. This is applicable to both 2D and 3D surveys. Shot holes will be drilled with a small rig mounted on either an airboat or marsh buggy. Holes are drilled to 100’ in depth and typically loaded with 2 kilograms of pentolite and safety-cap detonators. Receivers will be either single-point geophones or a small array of geophones, planted in the ground. Each geophone group either has internal solid-state recording capabilities within the geophone housing or is connected by a short wire directly into a small, autonomous digital recording unit. This eliminates the need for extensive stretches of wire to connect the geophone spread to a central recording “doghouse,” as was traditionally used by seismic crews. If the surface seismic recording is complemented by downhole recording in the injection well(s), the recordings will be made with DAS glass fiber installed during the completion of the well. The fiber is connected to an interrogator that pulses light down the fiber; slight delays in the returned light signal are measured to determine strain in the fiber and thereby measure the arrival of seismic waves at the borehole.

5.5.5.2 Wellbore Overview

The proposed wellbore design for WC IW-B No. 001 (Figure 5-13, page 31; *Appendix D-1*) consists of [redacted] surface casing run below the USDW, to be cemented in place per EPA Class VI standards. The wellbore will be designed with [redacted] casing, with premium connections from the surface to [redacted] above the top of the UCI ([redacted]). There will be a [redacted] crossover at that point. The casing will be [redacted] from that crossover to total depth (TD). The [redacted] casing will be set [redacted] into the bottom-sealing, intra-reservoir shale. The production tubing will be [redacted], with premium connections and a [redacted] production packer. The packer should be located approximately [redacted]. The packer location may change, provided there is at least [redacted] good cement bonding across the isolating shale directly above the top of the injection zone. The production packer will also be made of [redacted] material.

The proposed wellbore design for WC IW-B No. 002 (Figure 5-14, page 32; *Appendix D-3*) consists of [redacted] surface casing run below the USDW, to be cemented in place per EPA Class VI standards. The wellbore will be designed with [redacted] casing, with premium connections from the surface to [redacted] above the top of the UCI ([redacted]). There will be a [redacted] crossover at that point. The casing will be [redacted] from that crossover to total depth (TD). The [redacted] casing will be set [redacted] into the lower confining interval. The production tubing will be [redacted], with premium connections and a [redacted] production packer. The packer should be located approximately [redacted]. The packer location may change, provided there is at least [redacted] good cement bonding across the isolating shale directly above the top of the injection zone. The production packer will also be made of [redacted] material.

Annular and tubing pressures will be monitored in each well via downhole pressure gauges run on a fiber-optic-cable sensing package [redacted]. Pressures will be continuously monitored to ensure that well integrity is maintained. The fiber-optic-cable sensing package will include DAS and DTS technology to support carbon front-size monitoring through VSP surveys—if needed—and continuous temperature-monitoring capabilities. A SCADA monitoring system will be in place throughout the project's life.

As the first injection zone reaches capacity, those sands will be plugged and left behind. New perforations will be established in successively shallow sand packages to establish new injection horizons. This recompletion process will repeat from the deepest injection intervals to the top of the gross injection interval throughout the life of the well.

[redacted]

Figure 5-13 – WC IW-B No. 001 Wellbore Schematic (Initial Completion)

[redacted]

Figure 5-14 – WC IW-B No. 002 Wellbore Schematic (Initial Completion)

5.5.5.3 Equipment Overview

This section discusses example hardware setup and use of equipment for continuous downhole pressure and temperature monitoring that will employ fiber optic cable to communicate with a surface-located interrogator box, to record real-time or periodic data. Specific vendor-proprietary equipment will be provided when the vendor is selected nearer to the time the well is drilled. Specification sheets can be found in *Appendix F-2*.

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. Figure 5-15 illustrates the optical fiber, and Table 5-8 provides the specifications.

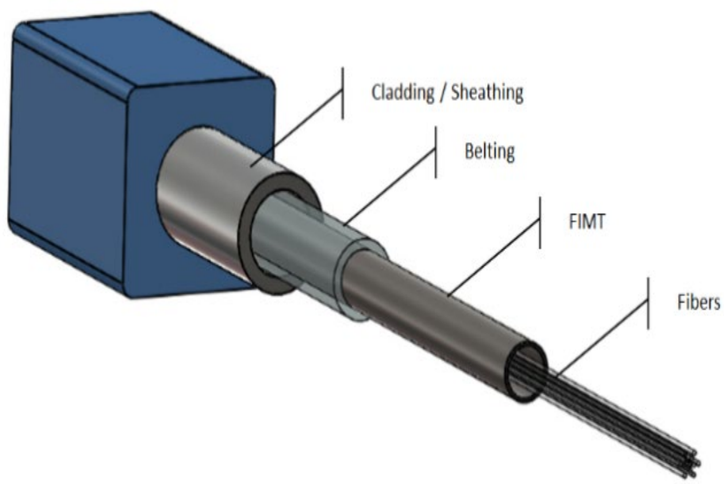

Figure 5-15 – SureVIEW with CoreBright Optic Fiber

Table 5-8 – SureVIEW Downhole Specifications

Description	Specifications
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)

<u>SureVIEW DTS Interrogator</u>

The SureVIEW DTS interrogator provides continuous monitoring, rapidly updating temperature profiles along the length of the completions. Its specifications are listed in Table 5-9.

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 sDAS Interrogator

The SureVIEW sDAS 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 (Table 5-10 and Figure 5-16).

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	0ºC to +40ºC / 32ºF to +104ºF
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 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

Figure 5-16 – SureVIEW WIRE Illustration

SureVIEW PT Gauge

The SureVIEW™ pressure/temperature (P/T) system is a fiber-optic-based monitoring system that provides reliable and accurate well monitoring. Each fiber-optic gauge measures both temperature and absolute pressure using established Fabry-Perot technology. With no downhole electronics, gauges can operate reliably at much higher temperatures than traditional electronic gauges, and they are immune to electromagnetic interference. Technical specifications are provided in Table 5-11 and an illustration is provided in Figure 5-17.

Table 5-11 – SureVIEW PT Gauge Specifications

SureVIEW P/T gauges	
Standard, high temperature (HT), and ultra temperature (UT)	
Operational temperature	86°F to 302°F (30°C to 150°C) standard 86°F to 482°F (30°C to 250°C) HT
Temperature accuracy	±1.8°F (±1°C)
Temperature resolution	0.2°F (0.1°C)
Pressure resolution	0.2 psi (0.014 bar)
Pressure range	15 psi to 15,000 psi
Dynamic Pressure Response	1,000psi per second
Overpressure	150% without performance degradation
Pressure accuracy	±5 psi (±0.3 bar)
Dimensions (length x width)	4 in. x 0.75 in. (10.0 cm x 2.0 cm)
Vibration	17g RMS, 10 to 2000 Hz
Shock	100g peak, 10 ms, half-sine
Material	A718
Porting options	Manifold, Testable Autoclave, Annulus

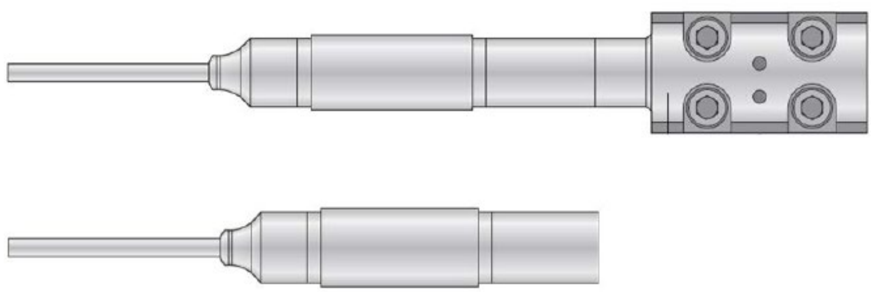

Figure 5-17 – SureVIEW Fiber PT Gauge

<u>SureVIEW PT Interrogator</u>

SureVIEW PT Interrogator is capable of interrogating up to eight SureVIEW fiber-optic P/T gauges to generate raw interferometric-signal information that it then converts into P/T values. Technical specifications are provided in Table 5-12.

Table 5-12 – SureVIEW PT Interrogator

Technical Specifications	
Description	**Specification**
Interrogator Model	Gen 3
Technology Supported	SureVIEW PT gauges
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	2U
Dimensions	19 in. x 3.47 in. x 19.8 in. (483mm x 88mm x 503mm)
Weight	20.3 lbs / 9.2 kg
Certifications	CE
Supply Voltage	24VDC
Power Consumption	Up to 35 Watts
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Humidity	5-75% RH (non-condensing)
Data Interface Connection	Ethernet or Serial RS-485
Internal Data Storage	64GB (> 1 year log capacity)
Fiber Connections	LC/APC (F3000)

Cross-Coupling Protectors

To protect the downhole cable, cross-coupling cable protectors are mounted at each tubing-joint coupling to protect the cable transitions across the coupling, as shown in Figure 5-18. There is a potential for the downhole cable to be damaged due to abrasion or crushing between the tubing and casing internal wall during the installation process, resulting in the loss of functionality of the associated downhole equipment.

Figure 5-18 – Image of Cross Coupling Protector

5.5.6 Monitoring Conclusion

The contents of this Testing and Monitoring Plan have been designed to satisfy all necessary requirements of SWO 29-N-6 **§3625.A** [40 CFR **§146.90**], specific to this project. Reporting and reevaluation requirements are explained and will be executed by Harvest Bend CCS for the life of the project. Monitoring strategies are included for injection-stream composition and conditions, bottomhole operating parameters, well integrity, above-confinement reservoir conditions, and

USDW composition. The planned well equipment to be used is included in their respective sections. The spatial distribution of monitoring wells is described and justified.

The time-lapse seismic surveying method for quantifying carbon front development over time has been well demonstrated. The time-lapse effect is primarily driven by the change in acoustic impedance resulting from the contrast in compressional velocity between high CO_2 concentrations and formation fluids. For Harvest Bend CCS, as formation fluids are displaced by CO_2, even at relatively low concentrations, the change in acoustic impedance during carbon front growth can be mapped to generate a time-lapse seismic image of the carbon front extent.

Most importantly, the need to add artificial penetrations (and risk inadvertently forming a conduit from confinement intervals) for monitoring purposes is eliminated with time-lapse seismic surveying and downhole gauges for accurate monitoring of carbon front migration.

Appendix F: Testing and Monitoring

- Appendix F-1 Monitoring Wells Plan Map
- Appendix F-2 Monitoring Equipment Specification Sheets

5.6 References

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