TESTING AND MONITORING PLAN
40 CFR §146.90

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information and Plan Overview

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

This Testing and Monitoring Plan describes how Oxy Low Carbon Ventures, LLC (OLCV), will monitor the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) site pursuant to 40 CFR §146.90. Testing and monitoring data will be used to demonstrate that the CO_2 Injection wells are operating as planned, the CO_2 plume and pressure front are behaving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDW). In addition, the testing and monitoring data will be used to validate and adjust the geocellular and simulation models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) re-evaluations and a non-endangerment demonstration at site closure.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

2.0 Overall Strategy and Approach for Testing and Monitoring

The Testing and Monitoring Plan was designed to monitor and mitigate the key risks identified for this project that are described in the Emergency and Remedial Response Plan (part of this application). During the Injection and Post-injection periods, those risks include the potential for: well integrity failure, leakage to USDW, natural disasters, induced seismicity or critical surface impacts. The testing and monitoring methods included in this document are mitigations and controls to prevent CO_2 or brine leakage out of the Injection Zone that could endanger the USDWs, migrate to a different stratum, or create a risk for people or the environment.

In addition, the testing and monitoring program is tailored to track the migration of the CO_2 plume and development of the pressure front within the Injection Zone. Data will be collected prior to injection to establish a baseline. Data collected during the injection and post-injection periods from the testing and monitoring program will help to validate the simulation models and re-evaluate the AoR.

The testing and monitoring program includes controls and mitigations in the following categories:

1. Carbon dioxide stream analysis
2. Continuous recording of operational parameters: injection rate, volume, pressure, temperature, and internal mechanical integrity
3. Corrosion monitoring and leak detection
4. Above confining zone monitoring, including the first permeable zone above the confining zone, which is coincident with the lowermost USDW, and the near-surface
5. Internal and external mechanical integrity testing
6. Pressure fall-off testing
7. Carbon dioxide plume and pressure front tracking
8. Surface Monitoring

The methodology and frequency of testing and monitoring methods is expected to change throughout the life of the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment. The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated.

Data obtained from the testing and monitoring plan will be used to inform operational decisions on the quantity and rate of CO_2 injected and potential containment actions. Data will be used to improve computational model forecasts. Data that is interpreted to be inconsistent with model predictions will trigger additional testing, monitoring and evaluation.

A summary of the proposed testing and monitoring methods and timing of testing and monitoring is listed in Table 1.

Table 1—Summary of Testing and Monitoring Frequency

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
CO_2 injectate stream analysis	On-line gas chromatograph and/or gas analyzers in flowline and sampling in flowline	Chemical and isotopic characterization prior to injection	Continuous monitoring using gas chromatograph and/or analyzers; quarterly or event-driven[1] sampling for composition; and isotopic analysis if capture process materially changes source stream	N/A
Continuous recording of operational parameters in injection wells: injection rate, volume, pressure, and temperature	Surface and tubing-conveyed pressure and temperature gauges, DTS fiber, and injection line flowmeter	Measurement prior to injection	Continuous measurement and recording	N/A
Corrosion Monitoring in injection wells and surface leak detection	Coupons, visual inspection at wellhead, LDAR/OGI cameras, surface sensors, and DTS	Inspection prior to injection	Quarterly coupon testing, weekly visual inspection, quarterly inspection via LDAR/OGI cameras, and continuous monitoring via surface sensors and DTS	Continuous surface monitoring and quarterly visual inspection until site closure
Internal mechanical integrity	Pressure and temperature gauges, DTS, Annulus pressure monitoring, tubing-casing monitoring	Measurement prior to injection	Continuous measurement and recording	N/A
External mechanical integrity testing	Pressure and temperature gauges, DTS, and MIT	Measurement prior to injection	Continuous measurement and recording; and routine MIT	N/A
Near well-bore formation properties testing (Pressure fall-off testing)	Pressure fall-off test	Measurement prior to injection	Once during every five-year period until plugging	N/A
In-zone pressure, temperature, CO_2 saturation and geochemistry	Pressure and temperature gauges and/or DTS; saturation logging, and fluid and dissolved gas sampling	Characterization prior to injection, including quarterly fluid and dissolved gas sampling; cased hole saturation logging; PT gauge	Continuous measurement and recording of pressure and temperature; annual saturation profile; event-driven* fluid sampling,	P/T: Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; saturation profile annually; event-

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
		and DTS measurements prior to injection	triggered by changes in P/T	driven* fluid and dissolved gas sampling, triggered by P/T data
Geochemistry of the first permeable zone above the confining zone and the lowermost USDW (Dockum Group)	Fluid and dissolved gas sampling and analysis in USDW1 well	Characterization prior to injection, including quarterly fluid and dissolved gas sampling for at least one year	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and, event-driven*, triggered by P/T data in SLR2 or SLR3 wells	Annually for first 10 years post injection pending an approved PISC plan; event-driven*, triggered by P/T data in SLR2 or SLR3 wells thereafter
Soil gas analysis (vadose zone; near surface)	Isotopic analysis and chemical evaluation at approximately 21 locations	Characterization prior to injection, including quarterly sampling for at least one year prior to commencement of injection	Quarterly gas composition sampling in years 1-3 and annually starting in year 4 for subset of stations, and event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluid sample results	Event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluids sample results
Containment of CO_2 in Injection Zone	Pressure and temperature gauges and/or DTS; saturation logging, and event-driven* fluid and dissolved gas sampling	Characterization prior to injection, including quarterly sampling for approximately one year in WW wells; saturation logging in the Upper Confining Zone in SLR1 and ACZ1	Continuous measurement and recording of pressure and temperature (SLR1 and WWs); event-triggered fluid sampling in WWs; saturation logging once every five year period in SLR1 and ACZ1 wells	P/T or DTS: continuously for the first 10 years in SLR1 well or until plugging, pending an approved PISC plan; Saturation logging: event-driven* in the SLR1 or ACZ1
Non-endangerment of shallow groundwater and soil	Geochemical and isotopic monitoring to detect deviations from expected groundwater and soil gas chemistry	Characterization prior to injection: quarterly	Groundwater and soil gas sampling: Quarterly analysis in years 1-3, then annually after that; and, event-driven*, triggered by P/T data in SLR wells	Event-driven*
CO_2 plume and pressure movement within the Injection Zone	Pressure and temperature gauges and/or DTS; and event-driven* fluid sampling	P/T measurement, fluid sampling prior to injection in the SLR2 and WW wells	Continuous P/T measurement in SLR2 and SLR3 wells; event-driven* fluid sampling in SLR or WW wells	P/T recording bimonthly for the first five years post-injection, then annually until well is plugged or plume

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
				stabilizes in SLR2 or SLR3 wells
Indirect geophysical monitoring of plume and pressure	2D VSP utilizing in-well fiber or wireline conveyed geophones; surface 2D; saturation logging; DInSAR and GPS	Prior to injection	Annual saturation logging in SLR2 and SLR3 wells; 2D VSP after 1, 2, 5 and 10 years; 2D surface seismic at year 10 and approximately every five years thereafter; Quarterly DInSAR and GPS	Annual saturation logging in SLR2 and SLR3 wells; surface 2D VSP once every approximately five-year period until plugging; 2D surface seismic once every approximately five years until plume stabilization Annual DInSAR and GPS for first five years post-injection
Presence or absence of seismicity	Seismometers	Prior to injection	Continuous monitoring and recording	Continuous monitoring and recording until site closure

[1]Event-driven sampling of CO2 injectate stream will be triggered if there are changes in the DAC process that may arise from facility upgrades or after facility shut-in periods.

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

2.1 Well Monitoring Network Design

Multiple testing and monitoring objectives described in Table 1 will be accomplished by evaluating data from monitoring wells (Table 2). These wells will provide direct measurements to compliment indirect measurement methods for monitoring the AoR. In addition, data from monitoring wells will be used to characterize fluid chemistry and isotopic composition throughout the stratigraphic column. A summary of data by well type is shown in Table 3.

OLVC plans to install a Single Reservoir-level (SLR) well, the SLR2, in the Injection Zone prior to the commencement of CO_2 injection, and OLCV has already installed a well to monitor the Underground Source of Drinking Water Aquifer (USDW) in the lowermost USDW, the Dockum

Group. The SLR3 well is anticipated to be drilled within five years after the commencement of injection and its location will be refined after commencement of operations. The need for additional monitoring wells will be evaluated as needed, and at least annually during the injection period and until plume stabilization. OLCV describes below the locations of monitoring wells to be installed prior to first injection and the proposed locations of future monitoring wells.

In addition to SLR2 and SLR3 wells, the Injection Zone will be directly monitored with data collected in four Water Withdrawal wells (WW). The WW wells will extract brine to manage pressure in the Injection Zone. The brine will be transported via pipeline for use in Oxy or third-party operations or transported to the location of planned Class I disposal wells. The CO_2 injectate plume is not expected to reach the WW1, WW3 and WW4. If the CO_2 plume does reach these WW wells, they will be shut in. The CO_2 injectate plume is expected to reach WW2. When the plume in the Holt sub-zone reaches WW2, the well will be plugged above the Holt and continue to produce brine from the upper portion of the Lower San Andres. The CO_2 injectate plume from the upper part of the Lower San Andres (Lower San Andres sub-zone and G1 sub-zone) is not expected to reach the WW2.

Note that OLCV previously intended to utilize the Shoe Bar 1 and Shoe Bar 1 AZ to monitor the first permeable zone above the confining zone. Wireline testing in the water withdrawal wells conducted in Spring 2024 indicates the absence of permeable zones above the confining zone and below the lowermost USDW. Therefore, the Dockum group is the both the lowermost USDW and the first permeable zone above the confining zone. The Shoe Bar 1USDW well will be used to monitor geochemistry in the Dockum group to meet 40 CFR 146.90(d).

Table 2—Planned wells used for monitoring

Regulatory Well Name	Project Well Name	Drill Date	Purpose	~TD (ft)	Latitude (NAD 27)	Longitude (NAD 27)
Shoe Bar 1	SLR1	2023	Upper Confining Zone Monitor	6585, ~4200[1]	31.76343602	-102.7034981
Shoe Bar 1AZ	ACZ1	2023	Upper Confining Zone Monitor	6725, ~4300[1]	31.74670102	-102.7259011
Shoe Bar 2SLR	SLR2	2025	Injection Zone monitor	5271	31.76448869	-102.7305326
Shoe Bar 3SLR	SLR3	~2030, five years after the commencement of injection	Injection Zone monitor	5316	31.76411900	-102.7316750
Shoe Bar 1USDW	USDW1	2023	Lowermost USDW monitor	850	31.78023685	-102.7418093
Shoe Bar 1WW	WW1	2024	Water withdrawal, Injection Zone monitor	5053	31.76289539	-102.6959232
Shoe Bar 2WW	WW2	2024	Water withdrawal, Injection Zone (G1-G4) monitor	5314, 4947[2]	31.78419981	-102.7275869

Shoe Bar 3WW	WW3	2024	Water withdrawal, Injection Zone monitor	5106	31.75008553	-102.7102206
Shoe Bar 4WW	WW4	2024	Water withdrawal, Injection Zone monitor	5337	31.76384464	-102.7539505

[1]Anticipated TD following conversion to monitor well
[2]Anticipated TD following plugging above Holt zone

Table 3—Summary of monitoring by well type and project stage

Well type	Objective	Method	Monitoring Pre-Injection	Monitoring During Injection	Monitoring Post-Injection
SLR2 and SLR3; Injection Zone monitoring	Direct monitoring of CO_2 plume and pressure front	Downhole and surface pressure and temperature gauges or DTS (selected wells)	Baseline sampling in SLR2	Continuous	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging
	Direct measurement of fluids to detect CO_2	Fluid and dissolved gas sampling via wireline or U-tube	Baseline sampling in SLR2	Event-driven*	Event-driven*, until plugging
	Indirect monitoring of CO_2 concentration	Pulsed Neutron Log (PNL) or Reservoir Saturation Tool (RST) log	Baseline sampling in SLR2	Annually	Annually until plugging
	Indirect geophysical monitoring of plume and pressure	2D VSP (selected wells)	Baseline survey in SLR2	At years 1, 2, 5 and 10 in SLR2	Once every approximately five-year period until plugging in SLR2
	Internal and external mechanical integrity	Pressure and temperature (P/T) gauges or DTS; and external MIT	Baseline data in SLR2	Continuous P/T MIT log once every five-year period	MIT log once every five- year period and before plugging
	Corrosion monitoring	Casing inspection logging	NA	Once every five-year period	Once every five-year period until plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	NA	Weekly to quarterly, depending on tool	Continuous surface monitoring and quarterly visual inspection until site closure
SLR1 and ACZ1; Upper Confining Zone monitoring	Direct monitoring of pressure and temperature to ensure Upper Confining Zone integrity	Downhole and surface pressure and temperature gauges and/or DTS (SLR1)	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan
	Indirect monitoring of CO_2 presence above the Injection Zone	PNL or RST log	Prior to injection	Once every five year-period	Event-driven* until plugging

	Internal and external mechanical integrity	Pressure and temperature gauges; external MIT	Prior to injection	MIT log once every five-year period	MIT log once every five-year period and before plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	NA	Weekly to quarterly, depending on tool	Continuous surface monitoring and quarterly visual inspection until site closure
USDW1; Lowermost USDW monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling using a bladder pump	Baseline sampling	Quarterly sampling in years 1-3, annually starting in year 4; and event-driven*	Annually for the first 10 years post injection pending an approved PISC plan; and event-driven*, until plugging
WW1, WW2, WW3, WW4; Injection Zone monitoring	Geochemical and isotopic monitoring to detect to detect CO_2	Fluid sampling at the wellhead	Baseline sampling	Event-driven*	Event-driven*, until plugging

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

2.1.1 Injection Zone monitoring wells

The SLR2 and SLR3 well locations were selected based on potential leakage pathway scenarios, and on the computationally simulated plume and critical pressure front. The modelled CO_2 plume and pressure front extends semi-radially from the BRP CCS1, CCS2 and CCS3 wells. SLR2 and SLR3 wells were placed to detect movement of the plume and pressure front.

OLCV proposes a phased drilling approach to allow for incorporation of operational data to the monitoring plan. The data obtained during early CO_2 injection may result in adjusting the well locations or timing of drilling. The proposed location, timing and data collected in SLR wells is described below:

- The Shoe Bar 1 well is a stratigraphic test well that was completed in February 2023. This well is located near the proposed BRP CCS3 CO_2 injector well and is within the maximum extent of the modelled AoR. For monitoring purposes the well will be referred to as SLR1. The Shoe Bar 1 well was not constructed with Cr25 casing; it will be plugged above the

Injection Zone prior to the commencement of CO_2 injection. The well contains DTS/DAS fiber that may be used during VSP seismic acquisition and for monitoring pressure and temperature above the confining zone. A baseline 2D VSP will be collected in the SLR1 (or in the BRP CCS3) prior to injection and will be repeated at 1, 2, 5 and 10 years after the commencement of injection.

- The SLR2 well will be drilled prior to the commencement of CO_2 injection or shortly thereafter (dependent on availability of CO_2 compatible casing) and will be located within the extent of the CO_2 plume created after approximately seven years of injection. Pressure and temperature will be monitored using downhole gauges and DTS fiber. Fluid samples from the Injection Zone may be collected, if pressure or temperature changes indicate a change in brine composition consistent with arrival of CO_2. A baseline 2D VSP will be collected in the SLR2 prior to injection and repeated at approximately 1, 2, 5 and 10 years after the commencement of injection. No CO_2 is anticipated to reach the SLR2 before year five of injection.

- The SLR3 well will be drilled within five years after the commencement of CO_2 injection and will be located within the maximum extent of the CO_2 plume created after 12 years of injection. Pressure and temperature will be monitored using downhole gauges. Fluid samples from the Injection Zone may be collected, if pressure or temperature changes indicate a change in brine composition consistent with arrival of CO_2. No CO_2 is anticipated to reach the SLR3 before year seven of injection. This well will be plugged when CO_2 reaches it unless CO_2 compatible casing is available and utilized at the time of construction.

The SLR2 and SLR3 wells will be completed with tubing and packer, will isolate the casing and formations in the Upper San Andres and Grayburg formations (Upper Confining Zone), and will have open perforations in the Lower San Andres (Injection Zone) to allow direct measurements in the Injection Zone (Figure 1). Pressure and temperature gauges will be tubing-deployed to track changes in reservoir conditions during the injection and post-injection periods. It will be possible to obtain fluid samples from the SLR2 and SLR3 wells to conduct geochemical analyses.

The figure below illustrates the design of proposed SLR2 well. Refer to Appendix A of the Injection Well Construction Plan for a wellbore diagram of SLR2 and SLR3. Note that a U-tube system for retrieving water samples is being considered for the SLR2 and SLR3. A U-tube system may allow for cost-effective sampling of fluids and dissolved gasses from the Injection Zone. However, there are few examples of this technology deployed to active projects in the field, therefore little is known about the expected life of the equipment at field conditions. Furthermore, existing U-tube systems are not typically deployed to reservoirs where H_2S is present. OLCV is working with vendors to determine whether a U-tube is appropriate for the reservoir conditions at the BRP Project.

U-tubes are not contemplated for water withdrawal wells, because the U-tube system would interfere with operation of the electrical submersible pump (ESP) installed to produce water. U-tubes are not contemplated for wells monitoring the confining zone (SLR1 or ACZ1) because frequent monitoring of fluid chemistry and dissolve gas is not planned for these wells, as no Injection Zone fluids are expected to reach these wells. A U-tube is not planned for the USDW1 well, because the well is designed with a bladder pump to efficiently sample fluids and dissolved gasses.

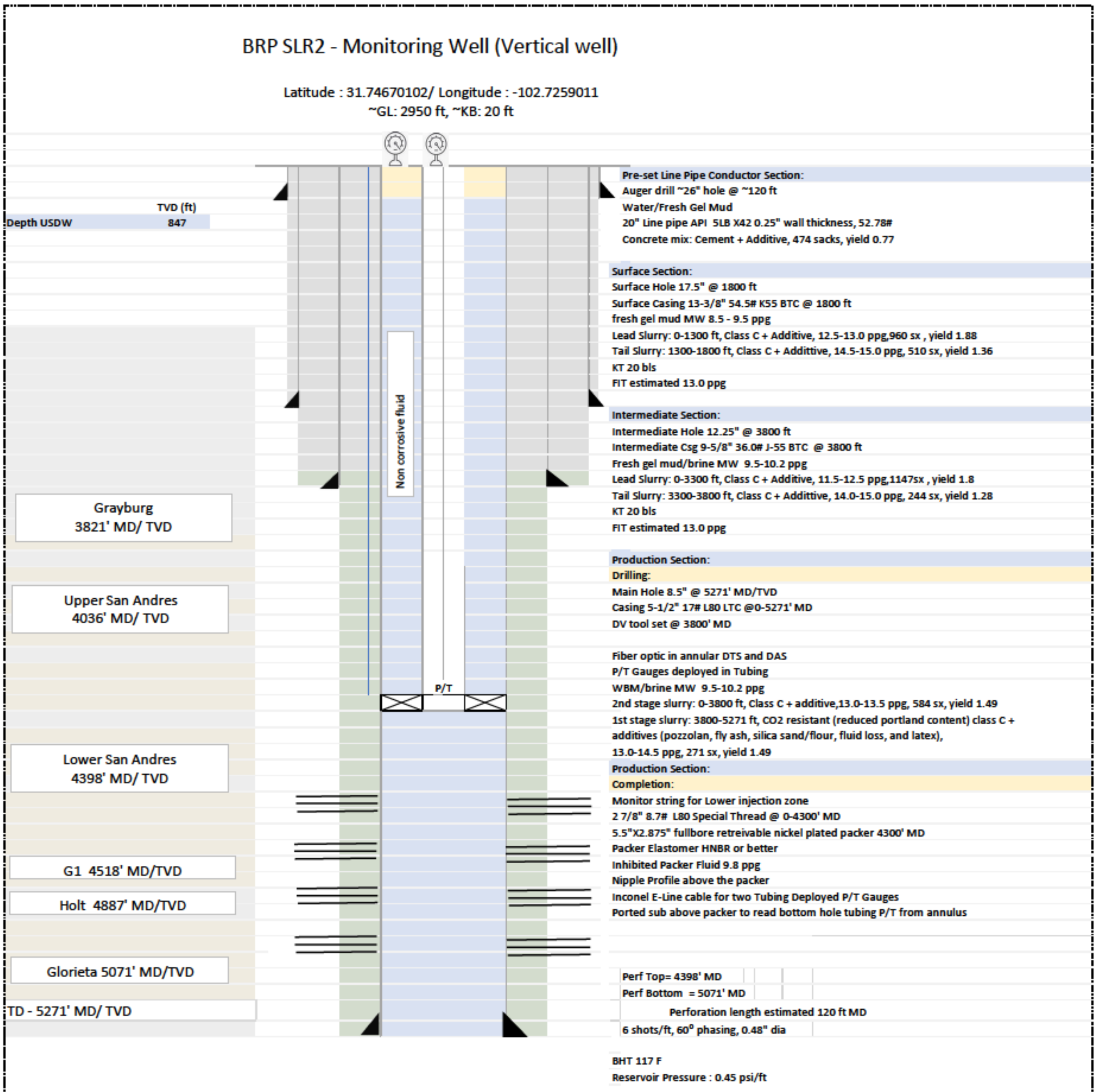

Figure 1—SLR2 schematic

2.1.2 Shoe Bar 1AZ well

The Project initially intended to convert the Shoe Bar 1AZ to be a monitoring well for the Yates formation, which was interpreted on log data from the Shoe Bar 1 and Shoe Bar 1AZ to the be first permeable zone above the Upper Confining Zone. However, wireline testing during construction of the Shoe Bar 1WW, Shoe Bar 2WW, Shoe Bar 3WW, and Shoe Bar 4WW shows the absence of permeable zones between the Upper Confining Zone and the lowermost USDW. The Dockum group is defined as the lowermost USDW. Therefore, the Dockum group is both the lowermost USDW and the first permeable zone above the confining zone. See Section 5 of Appendix A to the AoR document for a detailed description of testing and results.

The Shoe Bar 1AZ will be plugged above the Injection Zone prior to the commencement of injection. This well will be used to monitor integrity of the Upper Confining Zone through periodic saturation logging.

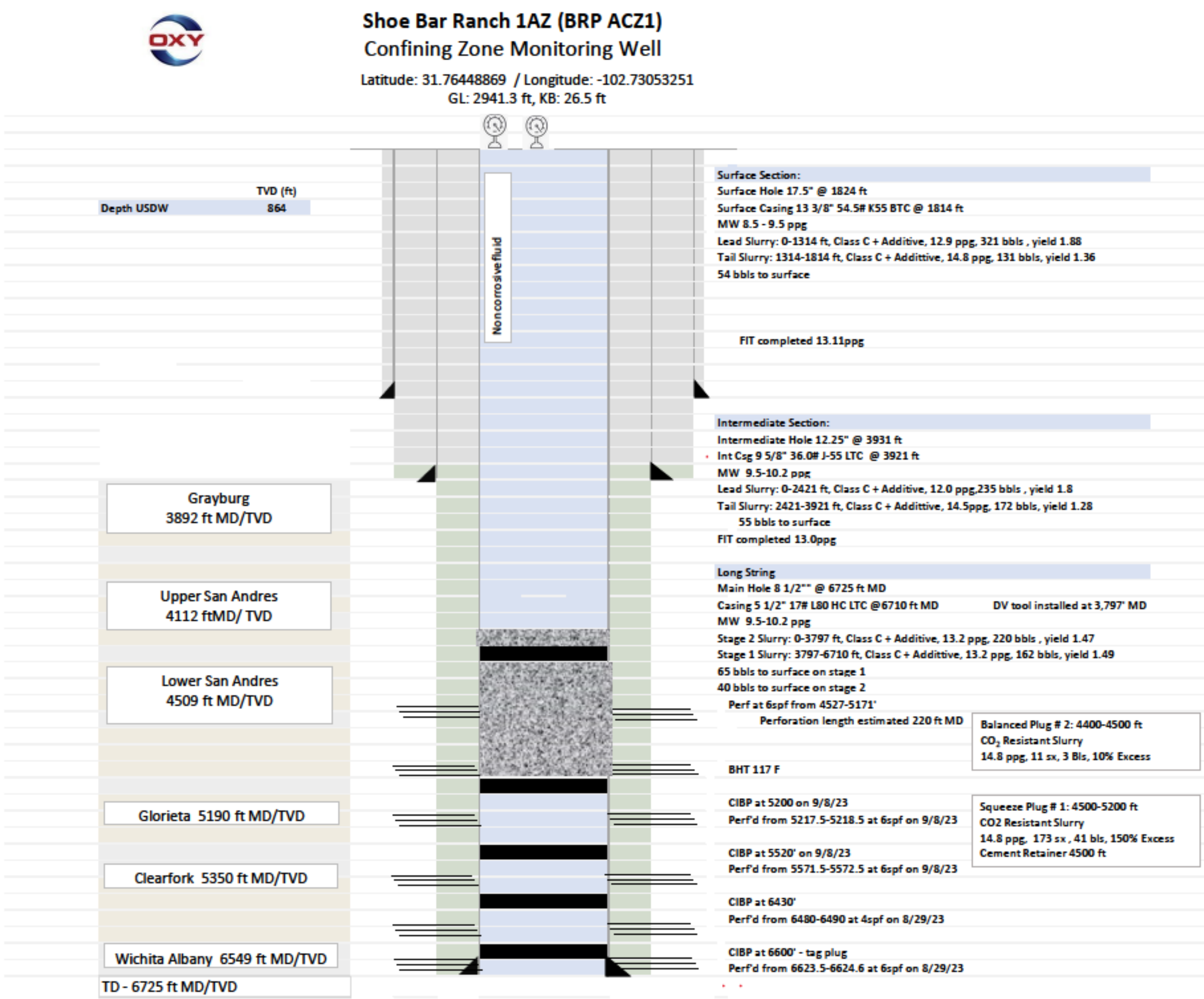

Figure 2—Shoe Bar 1AZ schematic after plugging above the Injection Zone

2.1.3 USDW Monitoring Well

A USDW-level well was drilled and completed in 2024 in the lower portion of the Dockum group, which is the lowermost USDW. This well will be used to collect baseline geochemical and isotopic information about the USDW prior to the commencement of CO_2 injection and will be used to monitor groundwater geochemistry and dissolved gas during the injection phase of the project.

The USDW monitoring well is located close to the BRP CCS1 and CCS2 wells and will be used to monitor the effects of the reservoir pressurization at the highest point of pressure and validate the sealing capacity of the Upper Confining Zone.

No other existing USDW wells are located within the expected AoR of the Project. Because the modelled AoR is small, ~2.5 miles in diameter, OLCV believes that one USDW well will provide sufficient monitoring data.

The figure below shows the wellbore diagram for the USDW1 well.

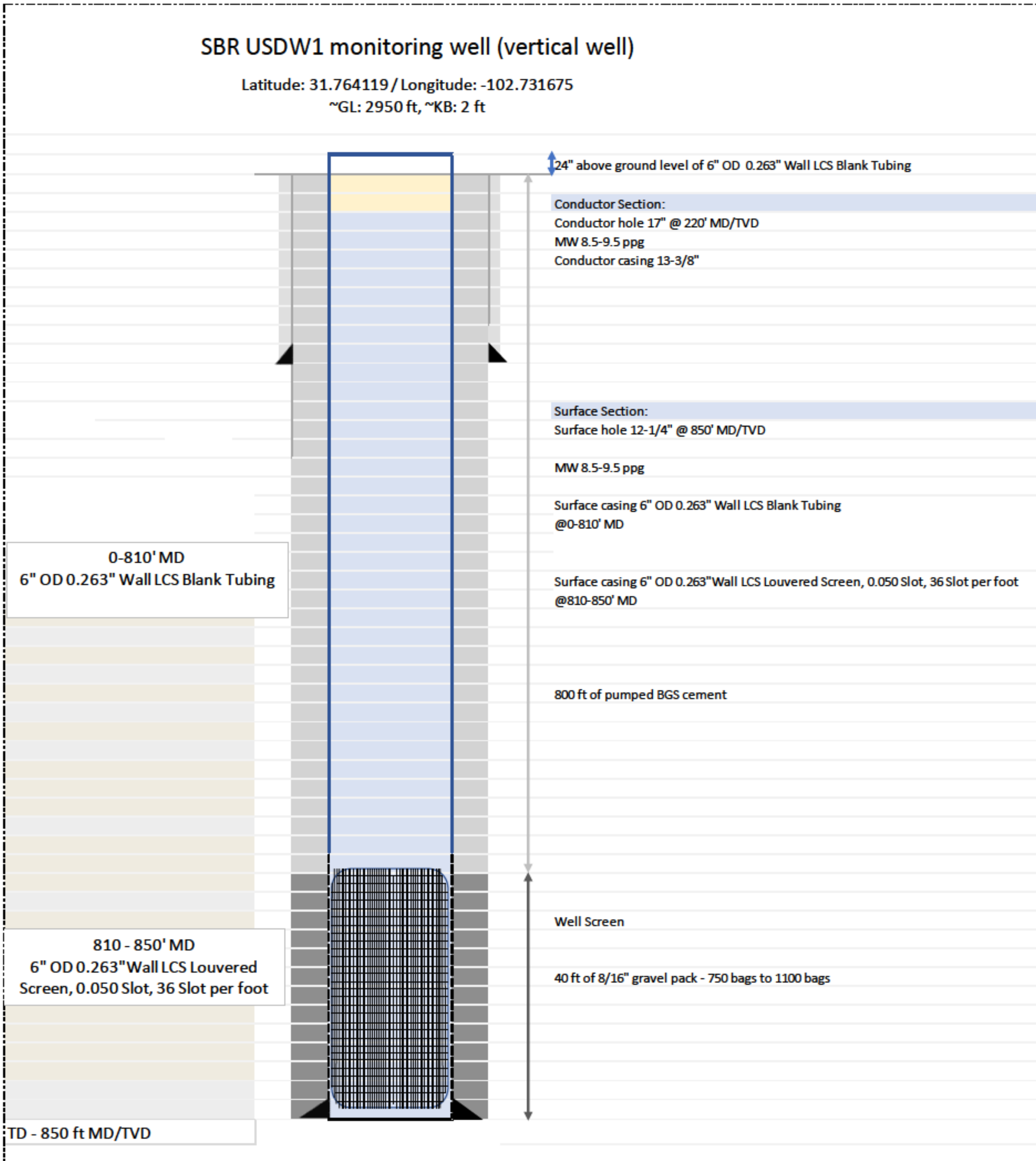

Figure 3—USDW Monitoring well

2.2 Other Monitoring Techniques

In addition to utilizing a well-based network to monitor pressure, temperature, and fluid and dissolved gas chemistry of the subsurface, OLCV will also utilize surface and near-surface methods to monitor CO_2 containment. Additional details on geophysical monitoring methods are described in Sections 11 and 12 of this document. Near-surface soil and soil gas monitoring is described in Section 8.2.

2.3 Quality Assurance Procedures Summary

A Quality Assurance and Surveillance Plan (QASP) for testing and monitoring activities, required pursuant to 40 CFR §146.90(k), is provided as a separate document.

2.4 Reporting Procedures Summary

OLCV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR §146.91.

3.0 Carbon Dioxide Stream Analysis

OLCV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR §146.90(a).

The source of the CO_2 for the Project is a Direct Air Capture (DAC) facility that is located near the proposed CO_2 sequestration site. The DAC facility will extract CO_2 from air, and the composition of the produced stream will be primarily composed of CO_2, O_2 and H_2O. The DAC extraction process prevents other components from being incorporated into the resulting stream.

3.1 Location and Frequency

The CO_2 injectate stream (Table 4) will be continuously monitored at the DAC facility before the injectate enters the flowline to BRP. In addition, the CO_2 injectate stream will be continuously monitored using an online gas chromatograph or gas analyzers directly upstream of the CO_2 Injector's wellheads. CO_2 stream samples will be routinely collected at a sample port in the flowline near the Injector wellheads. Continuous online monitoring of the CO_2 injectate composition, coupled with routine laboratory analysis will provide appropriate data resolution and, in the unlikely event that impurities are present, detect those impurities that might alter the corrosivity or other properties of the injectate downhole. See Table 5 for a summary of injectate monitoring plans.

The isotopic composition of the CO_2 stream will be analyzed prior to injection. This will allow for fingerprinting of the injectate stream and comparison with fluid samples obtained from SLR, WW or USDW wells during the Injection or Post-Injection periods.

If online gas chromatography / gas analyzer or laboratory analysis indicate that the CO_2 injectate stream exceeds the specifications described in Table 4, the system is alarmed to alert OLCV personnel. Based on operational experience, minor system upsets are resolved in a few minutes and the composition is restored to the specification. If the composition is not restored to the specification, or the source of the issue cannot be quickly resolved, CO_2 capturing operations at the DAC facility will be shut-in until the injectate stream meets the specification. If the DAC process is stopped, CO_2 stream will not move to the final compression system or enter the pipeline for transport to the sequestration site. This process ensures that the CO_2 stream composition entering the CO_2 Injectors is consistent with the expected composition.

Table 4—CO_2 Injectate Stream Specification

Component	Specification
CO_2 content	>95 mol% (>96.5 mass%)
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F
Isotopes	$\delta^{13}C$ and ^{14}C of CO_2

Table 5—CO_2 injectate stream monitoring method and frequency

Method	Pre-Injection	Injection	Post-Injection
Online gas chromatography / gas analyzer of supercritical CO_2 in the flowline upstream of the injector wells	NA	Continuously	N/A
Laboratory gas chromatography of samples obtained from a sample port upstream of the injector wells	N/A	Quarterly; or event-driven* if the DAC process materially changes	N/A
Laboratory isotopic analysis of injectate samples	Prior to injection	Event-driven* if the DAC process materially changes	NA

*Event-driven = changes in the DAC process that may arise from facility upgrades or after facility shut-in periods.

3.1.1 Stream Monitoring at DAC facility

The DAC facility will be equipped with an online analyzer including an O_2 optical sensor and a H_2O aluminum oxide sensor to continuously monitor for O_2 and H_2O and ensure the injectate stream meets specification. In addition, gas-phase samples at known temperature and pressure will routinely be collected from the DAC facility for laboratory analysis. The DAC facility will be equipped with an on-site laboratory to measure the composition and conduct isotopic analysis of the CO_2 stream. The DAC facility is designed to prevent CO_2 injectate from entering the pipeline to sequestration if the composition does not meet the specification.

3.1.2. Stream Monitoring in the Flowline

In addition to the continuous monitoring and on-site laboratory analysis at the DAC facility, the CO_2 stream will be continuously recorded and routinely sampled directly upstream of the flowmeter near the CO_2 injector wellhead (40 CFR §98.440-98.449). A gas chromatograph and/or gas analyzers will be installed along the flowline near the flowmeter and the data will be continuously monitored at a control room staffed with personnel employed by Oxy, OLCV or its subsidiaries or third-party contractors. A sample port will be installed directly upstream of the flowmeter to allow extraction of the CO_2 stream in a supercritical phase. The samples will be collected, transported to a laboratory, and analyzed by a qualified third-party contractor experienced with analyzing gases.

3.1.3. CO_2 Isotopic Analysis

In addition to the gas composition analysis, CO_2 stream samples from the flowline port will be collected for isotopic characterization. These data will be used to determine a baseline and complement the gas, soil, and water characterization methods. Samples for isotopic compositional baseline analysis will be sent to a commercial laboratory for evaluation.

3.2 Analytical Parameters

The 1PointFive DAC facility has developed a standard CO_2 specification, as shown in Table 4. OLCV will notify the EPA before any anticipated change in CO_2 composition. In addition, any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the established operating data specified in the permit, or a demonstration that these characteristics have not changed since the previous reporting period, shall be described in a semi-annual report, and submitted to the EPA in compliance with 40 CFR §149.91(a).

3.3 Sampling Methods

Sample collection for laboratory analysis will follow the procedure outlined in GPA-2177-20 to ensure that the sample is representative of the injected CO_2 stream. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the third-party authorized laboratory. A third-party contractor will be responsible for collecting the samples, transporting the samples to a laboratory, and for sample analysis.

3.4 Laboratory to be Used, Chain of Custody, and Analysis Procedures

The samples will be analyzed in accordance with GPA-2177-20 by a third-party laboratory. Sampling procedures will follow contractor protocols to ensure the sample is representative of the injectant and samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample handling and chain-of-custody guidance.

4.0 Continuous Recording of Operational Parameters

OLCV will install and use continuous recording devices to monitor injection pressure, rate, volume; the pressure on the annulus between the tubing and the long string casing; and the temperature of the CO_2 stream, as required by 40 CFR §146.88(e)(1), §146.89(b), and §146.90(b).

4.1 Monitoring Location and Frequency

Injection operations will be continuously monitored and controlled by the operations staff utilizing a process control system. The system will continuously monitor, control, record, and alarm for critical system parameters of pressure, temperature, and injection flow rate. The system will initiate a shutdown if specified control parameters deviate from the intended operating range and will allow for remote shutdown under emergency conditions. Trend analysis will aid in evaluating the performance (e.g., drift) of the instruments, indicating the need for maintenance or calibration.

Monitoring and metering locations and frequencies are summarized in Table 6 below.

Table 6—Continuous Monitoring Methods and Frequency

Objective	Method	Minimum sampling frequency	Minimum recording frequency
Injection pressure and temperature at surface	Surface gauges installed on injection line near wellhead	One second	30 seconds
Injection rate and volume	Mass flow meter on injection line near wellhead	One minute	One hour
Injection pressure and temperature downhole	Downhole tubing-deployed gauge above packer ported to tubing above packer	10 seconds	30 seconds
	DTS fiber	10 minutes	30 minutes
Pressure on the annulus between the tubing and long string casing	Downhole tubing-deployed gauges ported to annulus above packer	10 seconds	30 seconds
Annular pressure at surface	Pressure gauge installed in wellhead	One second	30 seconds
Annulus volume	Continuous pressure monitoring between tubing and production casing, and continuous monitoring of pressure at surface to confirm absence of leakage. Direct fluid level measurements may also be obtained, as triggered by pressure data.	10 seconds pressure gauge; fluid level as needed	30 seconds on pressure gauge, fluid level as needed

4.2 Description of Methods and Justification

4.2.1 Pressure and Temperature Monitoring

OLCV will monitor and measure injection pressure and temperature (P/T) three ways in the Injector well: downhole gauges, DTS and surface gauges. One P/T gauge will be installed downhole as part of the completion and ported into the tubing to continuously measure CO_2 injection P/T. The downhole sensor will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure.

A second P/T gauge will be installed on the outside of the tubing string above the packer to measure pressure continuously in the annular space above the packer and identify any potential loss of mechanical integrity.

At the surface, electronic pressure gauges and temperature sensors will be used to continuously monitor the pressure and temperature of the annulus between the tubing and long string casing. Gauges and sensors will be connected to the automation system to provide continuous data analysis as well as alarms for malfunctioning events when the values deviate from the intended operating range.

If the downhole gauges stop working between scheduled maintenance events, then the surface pressure limitation approved for this permit will be used as a backup until the downhole gauges are repaired or replaced. For calibration purposes, in lieu of removing the injection tubing, the accuracy of the downhole gauges will be demonstrated by using a second pressure gauge with current certified calibration lowered into the well at the same depth as the permanent downhole gauge.

In addition to gauges, fiber optic cable will be attached along the side of the casing and to a distributed temperature sensing (DTS) interrogator on the surface, which will provide a distributed temperature profile while injecting. This system will record temperature continuously to aid in monitoring the CO_2 behavior and detect any unforeseen mechanical integrity issue in the well.

4.2.2 Injection Rate and Volume Monitoring

The mass flow rate of CO_2 injected into the well will be measured using flowmeter skids with Coriolis meter in the CO_2 injection line near the interface with the wellhead, shown as FE-100 in Figure 4. Piping and valving will be configured to permit flowmeter calibration. A redundant pressure control valve will be installed to allow for continuous injection during routine maintenance of the device. The flow transmitter will be connected to a remote terminal unit (RTU) on the flowmeter skid.

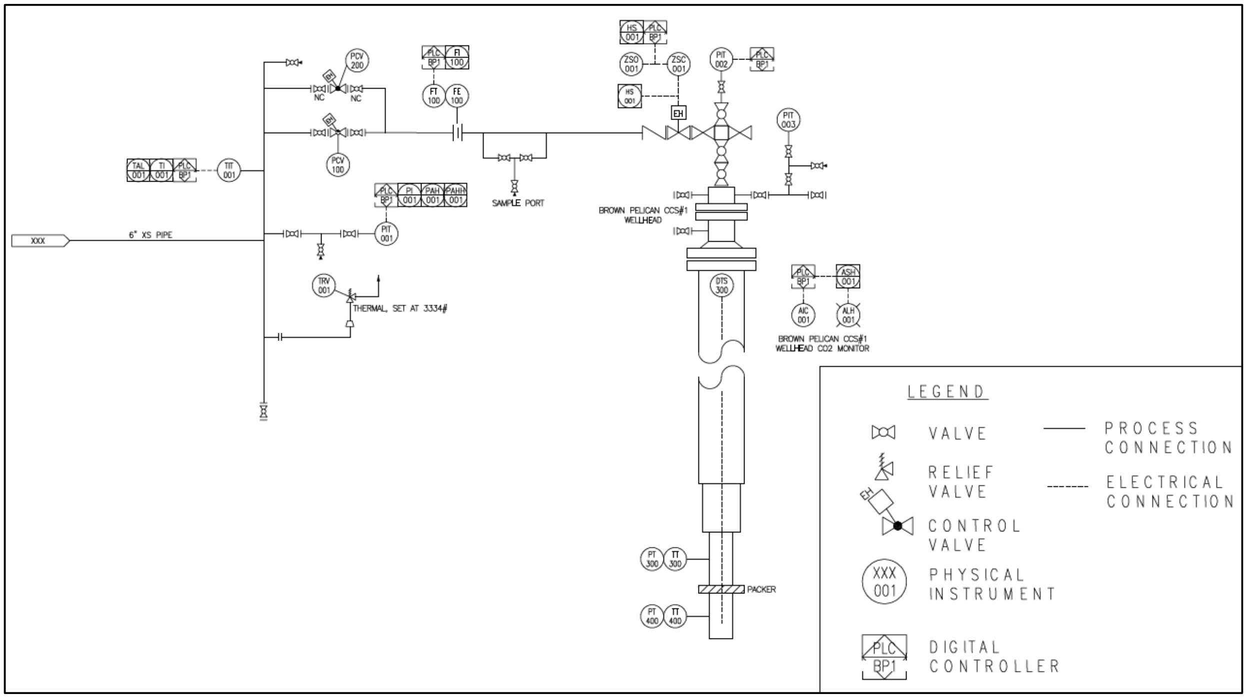

Figure 4—Representative example of wellhead process and instrumentation diagram

The process control system will limit the wellhead pressure to 1,800 psig to protect the surface equipment.

The project will follow the equations from 40 CFR Part 98-Subpart RR for CO_2 mass calculation.

4.2.3. Packer fluid / Annulus Volume Monitoring

The initial volume of packer fluid to fill the casing will be measured prior to the commencement of injection operations. Annular pressure will be kept between 100 and 400 psi on surface, and pressure data obtained from surface gauges and downhole gauges will be used to confirm the absence of unexpected changes in annulus volume. In addition, if there are changes in pressure, OLCV will conduct fluid level measurements to further confirm annulus fluid volume. This methodology will allow the operator to confirm the variation in annular fluid due to temperature changes v. potential mechanical integrity issues.

4.2.4. Justification of Continuous Monitoring Methods and Backup Options

Multiple measurements of P/T will be collected in the Injector wells to provide confidence in the data. Downhole and surface gauges are routinely used in well operations and have historically performed to expectation over the operational life of the well. DTS technology is relatively newer in operational deployment, thus its long-term performance history is less constrained. If DTS fails before the end of the monitoring period, gauges will be utilized to meet monitoring requirements.

In the event anomalous measurements are obtained from the P/T gauges or from DTS data, the gauges and wellhead will be manually inspected. Maintenance or repair operations on the instruments will commence, if required. If anomalous measurements are detected to be different between the gauges or DTS, an investigation into the cause will be conducted. OLCV will conduct appropriate repairs or adjustments and re-collect data.

The injection rate and volume metering protocols to be used at BRP follow the prevailing industry standard(s) for custody transfer as currently promulgated by the American Petroleum Institute (API), the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section 98.444(e)(3). These meters will be maintained and calibrated routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

5.0 Corrosion Monitoring and Surface Leak Detection

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

Materials (Table 7) have been selected to mitigate and inhibit corrosion. The suitability of the materials has been determined with published performance data from materials suppliers. A summary of materials is listed below. These materials will be monitored via coupons that will be exposed to the CO_2 injectate stream and reservoir fluids.

Table 7—List of Equipment with Construction Materials in Pipeline, Injectors, Injection Zone monitor and water withdrawal wells

Equipment Coupon	Construction Material
Pipeline	Carbon steel
Long string casing *above Injection Zone* in injection wells and Injection Zone monitoring and water withdrawal wells	Carbon steel, L80
Long string casing *in Injection Zone* in injection wells	Carbon steel coated, Super Duplex 2507 SS, #17, 80kpsi
Long string casing *in Injection Zone* for Injection Zone monitoring and water withdrawal wells	Carbon Steel, L80
Tubing *above packer* in injection wells	Coated carbon steel, L80, Coated TK-805
Tubing for Injection Zone monitoring and water withdrawal wells	Coated carbon steel, L80, Coated TK-805
Wellhead for injection wells, Injection Zone monitoring and water withdrawal wells	Alloy Steel DD specification
Injection tree and tubing hanger for injection wells	Sour service HH specifications
Packers for injection wells and Injection Zone monitoring and water withdrawal wells	Nickel-plated / HNBR (RGD) elastomers

5.1 Monitoring Location and Frequency

Corrosion monitoring of the CO_2 injection wells and water withdrawal wells will be conducted in a surface monitoring spool located near the wellhead that contains multiple access points. To measure corrosion, coupons or probes composed of well materials will be inserted at the access points in the spool, and those coupons or probes will be exposed to fluids being injected or produced from the wellbores. For Injection Zone and Confining Zone monitoring wells, a monitoring spool will be placed at the wellhead that is open to the tubing to monitor corrosion of the fluids/gas in the tubing. Coupons/probes will be collected and sent to a third-party company for analysis in accordance with NACE Standard SP-0775-2018-SG on a quarterly basis during the Injection Period and until wells are plugged in the post-injection period. Note that CO_2 is not expected to be encountered in the water withdrawal wells or in Confining Zone monitor wells.

In addition to coupons, OLCV will conduct visual inspection of the facilities, utilize optical gas imaging cameras (OGI), and evaluate data from DTS to monitor for potential leakage that could result from corrosion.

In the event that OLCV collects data that are consistent with possible corrosion, OLCV will re-conduct a visual inspection of the facilities, physical inspection using nondestructive techniques, re-collect data from coupons or optical gas imaging. In the event that corrosion is confirmed, OLCV will assess equipment fitness for service and take appropriate remediation actions.

Casing inspection logging will be conducted during planned well maintenance operations to evaluate downhole conditions and confirm absence of corrosion.

Table 8 provides a summary of the corrosion monitoring methods.

Table 8—Corrosion Monitoring and Surface Leak Detection Summary

Objective	Method	Pre-Injection	Injection	Post-Injection
Identify material corrosion in flowline and wellbore	Corrosion coupons	N/A	Quarterly	N/A
	Casing inspection log	Caliper cased hole log prior to injection operations	During planned well maintenance	N/A
Identify loss of mechanical integrity that could lead to corrosion	DTS	Prior to injection	Continuously	N/A
Surface monitoring and leak detection	Visual inspection and portable monitors	Prior to injection	Weekly	N/A
	OGI camera	Prior to injection	Quarterly	N/A
	CO_2 surface sensors	Prior to injection	Continuously	N/A

5.2 Description of Methods and Justification

5.2.1 Corrosion Coupons

Samples of injection well materials (coupons) will be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Coupons will be placed in a tray near the gas chromatograph / gas analyzer that is used to monitor the CO_2 injectate stream in the flowline. The coupon location will be safe and easily accessible for the vendor to retrieve. Coupons will be analyzed by a third party in accordance with NACE Standard SP-0775-2018-SG to determine and document corrosion wear rates based on mass loss. A summary of coupon parameters is shown in Table 9

Table 9—Summary of Analytical Parameters for Corrosion Coupons

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

Coupon data will be evaluated by OLCV engineers to confirm that well components meet the standards for material strength and performance. Appropriate corrective action will be taken if needed to restore the well components to meet operational standards.

5.2.2. Casing Inspection Logs

OLCV intends to perform casing inspection logging (CIL) during planned well maintenance. Between planned maintenance events, OLCV may conduct a CIL, if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards.

5.2.3. Surface detection methods

Field personnel will visit the Project location on a routine, at least weekly, basis to make observations of surface equipment, identify potential leaks, and verify that equipment is operating within design limits. Field personnel will be provided with handheld equipment to identify the presence of CO_2 as part of the safety requirements for the site.

Additional, quarterly, optical analysis using OGI cameras will be performed during the injection period. OGI cameras are highly specialized cameras that provide a method to spot invisible gases as they escape. These cameras rely on infrared images to detect the leaks and they will be used during the inspection of facilities, pipelines, and well locations.

6.0 Monitoring the Injection Zone

Injection-zone monitoring of pressure and temperature, saturation, and chemistry of fluids and dissolved gasses will be conducted to directly confirm the presence or absence of CO_2 at the monitoring well locations.

6.1 Monitoring Location and Frequency

The Lower San Andres Injection Zone will be directly monitored using the SLR2 and SLR3 monitoring wells. The SLR2 will be drilled prior to the commencement of CO_2 injection and will be located within the maximum extent of the pressure front resulting from CO_2 injection. The SLR3 well will be drilled within five years after CO_2 injection commences.

The Injection Zone will be indirectly monitored by the Shoe Bar 1 stratigraphic test well that will be plugged above the Injection Zone prior to the commencement of CO_2 injection. The portion of the well above the Injection Zone contains DTS/DAS fiber that may be used during VSP seismic acquisition and for monitoring pressure and temperature above the confining zone and indirectly informing containment in the Injection Zone.

Table 10—Monitoring of the Injection Zone

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
Pressure and temperature monitoring downhole	Downhole gauge ported to tubing and ported to annulus in injection wells	Prior to injection	Continuously, 10 second sampling and 5 minute recording frequency	Continuously for the first 10 years pending an approved PISC plan then annually until plugging;10 second sampling and 5 minute recording frequency
	DTS (planned for SLR2 and possibly SLR3)	In SLR2, prior to injection	Continuously, 10 minute sampling and 30 minute recording frequency	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; 10 minute sampling and 30 minute recording frequency
Pressure and temperature monitoring at surface	Surface gauge at injection well wellhead	Prior to injection	Continuously, 1 second sampling and 30 second recording frequency	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; 1 second sampling and 30 second recording frequency
Saturation profile	PNL or RST logging in SLR2 and SLR3 and WWs	In SLR2, prior to injection	Annually in SLR2 and SLR3; event-driven* in WWs	Annually until plugging
Fluid and dissolved gas geochemistry	Fluid and dissolved gas sampling and analysis in SLR2 and SLR3	During construction of injector wells, SLR wells and WWs and prior to injection to establish characterization	In SLR2 and SLR3, or WWs; Event-driven*, triggered by P/T data	Event-driven*, triggered by P/T data

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

6.2. Description of Methods and Justification

Pressure and temperature downhole and surface gauges will be installed in the SLR2 and SLR3. See Section 1.4.7 in QASP for description of gauges. In addition, the SLR1 well includes DTS fiber that will be used for indirectly monitoring the Injection Zone.

A pulsed neutron log (PNL) or other saturation lot (RST) will be collected in the SLR2 and SLR3 wells annually. This log is collected in cased holes and can be used to solve for water, oil, and gas saturations. Saturation logging may also be conducted in water withdrawal wells: WW1, WW2, WW3 and WW4.

Fluid and dissolved gas samples were collected while drilling the SLR1, ACZ1, WW1, WW2, WW3, and WW4 and will be collected in the future BRP CCS1, BRP CCS2, BRP CCS3, SLR2 and SLR3 wells. Additional fluid and dissolved gas samples will be conducted to constitute a baseline. These samples will be analyzed for their geochemical composition and isotopic characterization. If anomalous pressure and temperature changes are observed in an SLR well during injection or post-injection, fluid samples and/or dissolved gas samples will be obtained for geochemical and isotopic analyses and comparison with pre-injection samples.

7.0 Monitoring the First Permeable Zone Above the Confining Zone

The first permeable zone above the confining zone is the Santa Rosa formation, which is the lowermost member of the Dockum group. It will be monitored with the USDW1 well, a dedicated well that is located close to the BRP CCS1 and BRP CCS2 injection sites. Together with shallow groundwater and near-surface monitoring (See Section 8 of this document), OLCV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR §146.90(d). The results of ground water sampling will be compared to baseline geochemical and isotopic data collected during the site characterization baseline, consistent with 40 CFR §146.82(a)(6), to obtain evidence of potential fluid or gas movement.

7.1 Monitoring Location and Frequency

The zone of highest pressure, and thus highest potential for fluid movement, is close to the injection wells. The USDW1 well will monitor for potential loss of containment through the confining layers. Because the size of the BRP plume is expected to remain small (<6 miles^2), OLCV models that one well is sufficient to monitor above the confining zone. Additional monitoring wells for the USDW may be drilled in the future, depending on the shape and location of the CO_2/pressure plume.

The integrity of the Upper Confining Zone will also be monitored by the Shoe Bar 1 and/or Shoe Bar 1AZ stratigraphic test wells that will be plugged above the Injection Zone prior to the commencement of CO_2 injection. Saturation logging (PNL or RST) will be conducted in the wells in the intermediate hole section including the Grayburg and Upper San Andres formations. PNL and RST logs yield less reliable data through three casing strings, therefore, this method will not be appropriate for monitoring saturation in the lowermost USDW.

Monitoring above the confining zone is summarized in Table 11.

Table 11—Monitoring above the Injection Zone

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
First Permeable zone above the confining zone / lowermost USDW: Dockum				
Fluid and dissolved gas geochemistry in the first permeable zone above the confining zone	Fluid and dissolved gas sampling and analysis in USDW1	During construction and quarterly during baseline	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry	Annually for first 10 years pending an approved PISC plan; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry
Upper Confining Zone integrity				
Estimate CO_2 saturation in the Upper Confining Zone	PNL or RST in SLR1 and ACZ1	Prior to injection	Every five years	Event-driven*
Pressure and temperature in the Upper Confining Zone	DTS in SLR1	Prior to injection	Continuous measurement and recording of pressure and temperature	Event-driven*

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

7.2 Description of Methods and Justification

See Section 8.1 for details on fluid sampling and analyses.

8.0 Monitoring the Near-Surface

The primary objectives of the near-surface monitoring program are to confirm containment of CO_2 within the Lower San Andres Injection Zone, demonstrate protection of the deepest USDW, and to provide for early detection of anomalous conditions indicative of potential leakage of CO_2 or of brine migration. Water composition in shallow wells and soil gas within the near-surface has considerable variation due to natural processes and naturally occurring events and due to anthropogenic processes unrelated to the Project. Such natural and anthropogenic variation increases the difficulty of using only composition as the baseline for CO_2 leak and brine migration monitoring purposes. Instead, characterization of the subsurface system, including near-surface conditions (i.e., soil gas, fluid and dissolved gas chemistry of the deepest USDW; Section 7.0), and target injection reservoir fluids (see discussion in Section 6.0), provides a better approach for identifying unique tracers in the system that will potentially help identify an anomalous change in condition, and if needed, the source of the changes and discard false positives associated with potential CO_2 leaking or brine migration from the storage complex.

For the BRP Project, the lowermost USDW and soil gas within the AoR will be monitored in accordance with 40 CFR §146.90(d) and 40 CFR §146.90(h), respectively, and at the frequencies specified in Table 12.

Table 12—Monitoring the Near-Surface

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
Fluid and dissolved gas geochemistry in the lowermost USDW	Fluid and dissolved gas sampling and analysis	During construction and quarterly during baseline	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry	Annually for first 10 years pending an approved PISC plan; and event-driven*, triggered by P/T or soil gas chemistry
Soil gas analysis in the near-surface vadose zone	Isotopic analysis and chemical evaluation at approximately 21 locations	Characterization prior to injection, including quarterly sampling for at least one year	Quarterly gas composition sampling in years 1-3 and annually starting in year 4 for subset of stations, and event-driven*, triggered by P/T data in SLR wells and fluid sample results	Event-driven*, triggered by P/T data in SLR wells and fluid sample results

* OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and

dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

8.1. USDW Sampling

8.1.1 Monitoring Location and Frequency

The Project has drilled one well to monitor the Dockum group (i.e., Shoe Bar 1USDW or USDW1). The monitoring well is located close to the proposed BRP CCS1 and BRP CCS2 locations.

Note that one existing USDW-level well (Serial No. 4511701) was drilled in 1940. This well was located in the AoR during the evaluation of artificial penetrations and was determined to have low mechanical integrity. The 4511701 well was plugged and abandoned using hydrated Baroid 3/8" bentonite hole plug chips from 189 ft bgs to 5ft bgs and a cement slurry to the ground surface. There are no other existing USDW-level wells within the AoR.

Fluid and dissolved gas samples were collected after the installation and adequate development of the Shoe Bar 1USDW. Additional samples will be collected quarterly for at least one year prior to commencement of injection. Quarterly sampling commenced in June 2024. These samples will be analyzed for their geochemical and isotopic characterization shown in Table 13. After injection commences, Shoe Bar 1USDW will be sampled for geochemical analysis and a subset of the isotopic analyses at a quarterly frequency in years one to three, then annually starting in the fourth year after commencement of injection until the end of injection period. During the post-injection phase of the Project, the USDW will be monitored annually for geochemical analysis and a subset of the isotopic characterization for the first 10 years. If anomalous soil gas chemistry is observed, anomalous pressure and temperature changes are observed a SLR well, or there is any indication of leakage through the injection wells during the injection and post-injection phases of the Project, additional fluid samples may be obtained for geochemical and isotopic analysis and comparison to pre-injection sample results. If geochemistry data of fluids and dissolved gasses in the lowermost USDW are consistent with the absence of introduced Injection Zone brine or CO_2 injectate into the USDW, this monitoring method will be discontinued after 10 years post injection.

8.1.2. Description of Methods and Justification

The purpose of monitoring above the confining zone is to identify potential geochemical changes due to the introduction of CO_2 injectate stream or displaced formation fluids above the primary confining zone. Unlike some injected materials regulated by UIC, the presence of CO_2 in groundwater, surface water or soils may be the result of naturally occurring biological processes. Therefore, the presence of CO_2 in shallow or surface intervals is not necessarily diagnostic of leakage from an Injection Zone (Romanak, 2012). Furthermore, it may be impossible to establish a meaningful baseline CO_2 concentration, because the concentration of CO_2 in soils and groundwater is changing overtime due to global climatic changes (Bond-Lamberty, 2010; Macpherson, 2008; and Burger, 2020). However, the monitoring plans for the BPR project is designed to establish observable trends to characterize variabilities and changes due to natural processes and anthropogenic sources during the baseline phase of the Project.

In addition to establishing a baseline, OLCV plans to use a process-based approach along with natural tracers to characterize and attribute CO_2 measured in groundwater. The process-based approach involves characterizing groundwater prior to the commencement of injection operations. For the purpose of characterizing groundwater prior to injection while accounting for variations due to existing natural processes (and anthropogenic sources other than OLCV, if any), multiple samples will be collected during pre-injection activities. Similarly, multiple soil gas samples from across the AoR will be used to characterize the naturally-occurring variability across the site. See Section 8.2 in this document for more information on soil gas characterization.

For the process-based approach using natural tracers in groundwater, Romanak (2012) recommends characterizing $\delta^{13}C$, ^{14}C, CH_4, and δD in the fluids throughout the stratigraphic column. These isotopes can be used to trace carbon reactions. The initial characterization is intended to define components that will be diagnostic for future monitoring. In order to attribute the source of CO_2 or other relevant compounds, isotopic characterization will also be performed on the injectate fluid, fluids from the Injection Zone, fluids in first permeable layer above the Injection Zone, and fluids and dissolved gasses from the USDW.

To monitor changes, Romanak (2014) suggests using the covariation of δ13C and 14C as natural tracers. δ13C in anthropogenic sources overlaps the signature of naturally-occurring biologic sources, so the data should be considered in context with other lines of evidence. However, 14C in CO_2 is interpreted to be diagnostic between anthropogenic and naturally-occurring sources. The BRP has a unique challenge in that the source of the CO_2 injectate is captured directly from the ambient air that may contain signatures of multiple anthropogenic sources rather than from a specific industrial anthropogenic source, thus the ability to use the variation of δ13C and 14C for attribution is not well-studied.

To support the interpretation of the isotopic characterization of the natural tracers such as the variation of δ13C and 14C, geochemical properties of the lowermost USDW fluid will be characterized and a baseline will be established. Geochemical changes in the Dockum group may occur after the inadvertent introduction of foreign fluids or gases to the aquifer through a leakage pathway or conduit (i.e., CO_2 and/or brine migration from the target injection formation) during the injection phase of the Project (EPA, 2013).

At the end of the pre-injection monitoring period, OLCV will establish geochemical and isotopic trends, including seasonal variations, which characterize the natural or existing conditions in the USDW. These trends will be used to create procedures for CO_2 and brine leakage identification and characterization in the Dockum group during the injection and post-injection phases of the BRP.

The table below lists the components that will be characterized and monitored in the groundwater collected from the monitoring wells at BRP.

Table 13—Water Analysis Parameters

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and

				sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil;	20% of all analyses are either check/reference

			δ^2H: 2.0 per mil	standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the University of AZ	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation
Laboratory Analyte	**Analytical Methods[1]**	**Detection Limit / Range[2]**	**Typical Precision[2]**	**QC Requirements**
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup;

				CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	Method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130

				and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; $\delta^{2}H$: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/-

	University of AZ			0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

Notes:

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

Water samples in the Shoe Bar 1USDW will be collected in appropriate containers provided by the laboratories according to EPA best practices by a qualified and experienced third-party contractor(s) as described in the QASP. All sample containers will be labeled with a unique sample identification number and sampling date, written with durable labels and indelible markings. The water samples will be preserved appropriately, as required by the specific analytical methods, and shipped within 24 hours of collection to certified laboratories, under chain-of-custody control.

Groundwater analyses from the Dockum group will be performed by third-party laboratories accredited with the EPA and/or the Texas Commission on Environmental Quality (TCEQ), following the specific methods approved by EPA or alternative methods (e.g., ASTM Methods or Standard Methods). Operators might audit the procedures and results of the selected laboratories with a third party to review laboratory internal quality control procedures. The samples will be analyzed by a third-party laboratory using standardized procedures for various instruments including for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Sampling methods and chain of custody procedures are described in the QASP.

OLCV personnel experienced in fluid geochemical and isotopic analyses will evaluate the analytical reports provided by the laboratories who analyzed the fluid samples. These data will be compared with previous measurements to look for trends or changes in chemical composition. Groundwater results will be evaluated along with pressure and temperature data to determine the presence or absence of Injection Zone fluid or fluid migration above the confining zone.

An anomalous detection of CO_2 above background levels in the USDW "does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists" (EPA, 2013b). Therefore, if it is determined that a departure between observed and baseline parameter patterns appears to be related to a potential CO_2 leak from the target reservoir, additional testing of the USDW may be conducted. If OLCV personnel interpret that fluids or gases from the Injection Zone may be leaking into permeable zones above the confining zone, the source of the potential leak will be investigated, and appropriate corrective actions will be taken to protect the drinking water resources within the AoR.

The elements of the USDW monitoring program may be modified throughout the baseline, injection, and post-injection operational phases of the project, as needed, and with approval of the Director, as more data and information become available for the Project.

8.2. Near-Surface Soil and Soil Gas Sampling

8.2.1 Monitoring Location and Frequency

The collection of soil gas data within the AoR will aid in the identification, characterization, and source-attribution of CO_2 encountered in the near-surface. The evaluation of near-surface data is complicated by the variations in natural processes in the vadose zone (e.g., root respiration, biologic respiration, microbial oxidation of methane), anthropogenic sources unrelated to the BRP (e.g., nearby oil and gas production), gases from deeper zones (e.g., shallow groundwater), and atmospheric exchanges driven by barometric differences, which can be seasonal (NETL, 2017). As stated by the EPA (2023b), background soil CO_2 concentrations and isotopic compositions are largely "dependent on exchange with the atmosphere, organic matter decay, uptake by plants, root respiration, deep degassing, release from groundwater due to depressurization, and microbial activities." Therefore, some component of soil gas monitoring during the baseline phase of the project is useful to i) define the baseline molecular and isotopic compositions of the shallow soil gas, and ii) characterize natural background variability, including seasonal trends. The results of the pre-injection soil gas monitoring may then be used for future reference and comparison to operational soil gas monitoring to assist in the detection, validation, and quantification of potential CO_2 leakage. To this end, a soil gas monitoring program will be conducted during pre-injection and injection utilizing permanent soil gas probes as an active, whole air, sample collection method.

Permanent subsurface soil gas probes will be installed at 21 representative locations throughout the surface projection of the AoR and adjacent DAC facility. Installation commenced in June 2024 and will extend through July 2024. The following factors were considered in siting soil gas probes: the location of artificial penetrations discussed the Area of Review and Corrective Action Plan; variable surface soil characteristics, such as caliche deposits; the potential effects of the Direct Air Capture (DAC) facility on natural processes in the near-surface; and the location of adjacent property owners. Three probe stations are located near the proposed injection wells, where highest pressures and risks of vertical migration are expected. One probe station is located near each artificial penetration within the AoR (i.e., the BRP verification/monitoring wells and heritage wells). Two probe stations are located near the DAC facility and three probe stations are located along the southern boundary of the Shoe Bar Ranch property boundary near the adjacent private property.

Soil gas samples are collected after the installation of probes. Additional soil gas samples will be collected on a quarterly basis before beginning CO_2 injection over a period of at least one year. These samples will be analyzed for geochemical and isotopic composition shown in Table 14 to evaluate and characterize the near-surface conditions prior to injection. After CO_2 injection commences, the soil gas probe stations will be sampled quarterly for gas composition analysis between year one to three, then a subset of the soil gas stations will be strategically selected based on the previous data collected and sampled annually starting in year four for gas composition analysis. In addition, during the injection and post-injection phases of the Project, if anomalous pressure and temperature changes are observed in the SLR wells, or there is any indication of CO_2 leakage through the injection well, additional soil gas samples may be collected for gas composition and/or isotopic analysis and comparison to pre-injection sample results or deeper zone fluid analysis results.

The elements of the soil gas monitoring program may be modified throughout the pre-injection and injection phases of the Project, as needed, as more data and information become available for the Site.

8.2.2 Description of Methods and Justification

Soil gas characterization and monitoring will be used in concert with fluid analyses to conduct a process-based approach according to the principles described in Romanak (2012). The process-based approach is based on the observation that for every one volume percent of O_2 that is utilized by a microbe during respiration, one volume percent of CO_2 is produced. This relationship of O_2 to CO_2 forms a respiration trend line. Samples that plot to the left of the respiration line indicate natural biological processes. Samples that plot to the right of the respiration line indicate that excess CO_2 has entered the soil (see Figure 5). The source of the excess CO_2 could potentially be attributed to leakage from an injection site, or leakage from a geologic source such as the mantle, or an anthropogenic source other than the OLCV Project.

In addition, Romanak (2012) suggests that using the ratio of N_2 to CO_2 (Figure 5) can be used to detect anomalous introductions of CO_2 into a system. An increase in CO_2 can result in relative dilution of N2 in percent gas concentration. This relative reduction in N2 may indicate a deviation from the natural signal and could be result of CO_2 leakage. In the cases of CO_2 v. O_2 and CO_2 v. N_2, the naturally-occurring ratios are consistent despite seasonal or longer-term variability (Figure 5). Variability due to short or long term naturally occurring processes fall along the same trend, but at different points on the line.

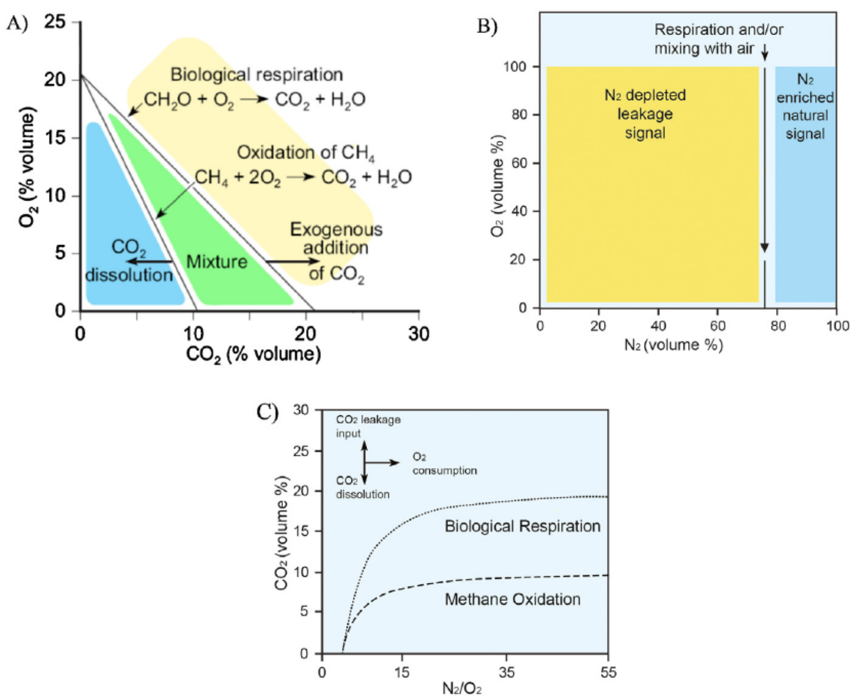

Figure 5—Process based approach for characterizing CO_2 source (modified Romanak, 2014)

As a result, the collection of soil gas samples for gas composition analysis can provide valuable information in the source attribution process for the presence of CO_2 and other gases in the vadose zone. However, the evaluation of the composition gas can be obscured in the light of the various biological processes present in the subsurface which produce or consume CO_2 (Romanak, 1997). Therefore, the collection and analysis of hydrocarbon gas as well as natural tracers (δ13C and 14C) can increase confidence in the interpretation of the data and the attribution of the CO_2 sources (i.e., natural vs. anthropogenic). Several studies have also demonstrated that analysis of soil gas for stable isotopes (δ13C and δD) and hydrocarbons (C2-C3) can help determine whether the presence of the CO_2 and methane is due to natural biological processes or from thermogenic sources (e.g., reservoir deep gas) (Romanak, 2014).

Soil gas probe sites will be installed to a depth of approximately 10 feet below ground level, dependent upon the depth to shallow groundwater and presence of low-permeability (e.g., clay) zones, utilizing either a direct-push (e.g., GeoProbe®) or hand-auger drilling equipment. During borehole advancement, a continuous soil core will be collected and logged in accordance with Unified Soil Classification System (USCS) guidelines to determine soil type. Additionally, up to three soil samples per location will be collected in general accordance with EPA Method LSASDPROC-300-R5 (EPA, 2023a) for the laboratory analysis of pH, electrical conductivity, sodium adsorption ratio, total organic carbon (TOC), and soil moisture, in accordance with the methods specified in Table 14 below.

Table 14—Soil and Soil Gas Analysis Parameters

Parameter	Analytical Method
Soil Analyses	
pH	EPA Method 9045D
Electrical Conductivity (EC)	29B_EC
Sodium Adsorption Ratio (SAR)	29B SAR
Total Organic Carbon (TOC)	Walkley Black 9060A
Moisture	SW3550
Soil Gas Analyses	
Composition gas: H_2, He, O2, N_2, CO_2, CH_4, CO, Ar, C2-C6+	In-house Lab SOP, similar to RSK-175
*$\delta^{13}C$ of CO_2 and CH_4	Gas chromatography/ combustion/ isotope ratio mass spectrometry
*C^{14} of CO_2	Accelerated mass spectrometry
*δD of CH_4	Gas chromatography/ combustion/ isotope ratio mass spectrometry

Note:
* = Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the project.

The installation of the permanent soil gas probes will be conducted in accordance with EPA operating procedure LSASDPROC-307-R5 (EPA, 2023b). To construct the soil gas monitoring stations, a drilling contractor will drill 2.25-in diameter boreholes to a depth up to 10 ft, depending on the thickness of the vadose zone and soil type encountered (Figure 6). Stainless-steel vapor implant points will be attached securely to 1/8th-inch Nylaflow® tubing and lowered to the bottom of the borehole. A sand pack using U.S. mesh interval 20/40 sand will be installed to approximately

6-inches above the vapor implant point as a filter pack. The remainder of the borehole will be backfilled with granular bentonite to the ground surface and hydrated to create an annular seal. The upper 1-foot of tubing will be encased within 1-inch diameter, schedule 40 polyvinyl chloride (PVC) pipe at the surface. The tubing will be threaded through a drilled, tight-fitting PVC slip cap and sealed from atmospheric air utilizing a stainless-steal Swagelok® capping fitting. The tubing at the surface will be concealed within a 6-inch steel, flush mount manway, individually installed with a concrete pad, for protection and easy accessibility. General information for each sampling station location will be recorded, including project name, borehole designation, borehole total depth, date and time of completion, borehole GPS location information, soil gas probe construction, and field personnel information.

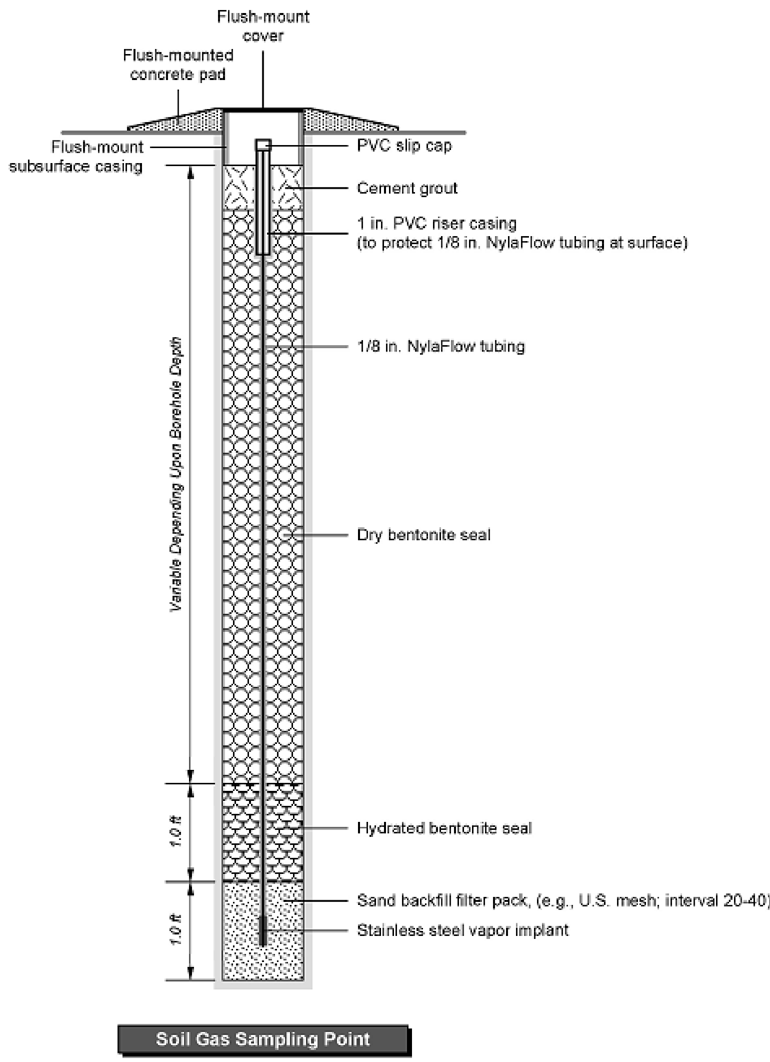

Figure 6—Soil gas probe installation diagram.

Permanent subsurface soil gas probes will be installed at approximately 21 representative locations throughout the surface projection of the AoR and adjacent DAC facility (Figure 7). The following factors will be considered in siting soil gas probes: the location of artificial penetrations discussed the Area of Review and Corrective Action Plan; variable surface soil characteristics, such as caliche deposits; the potential effects of the Direct Air Capture (DAC) facility on natural processes in the near-surface; and the location of adjacent property owners.

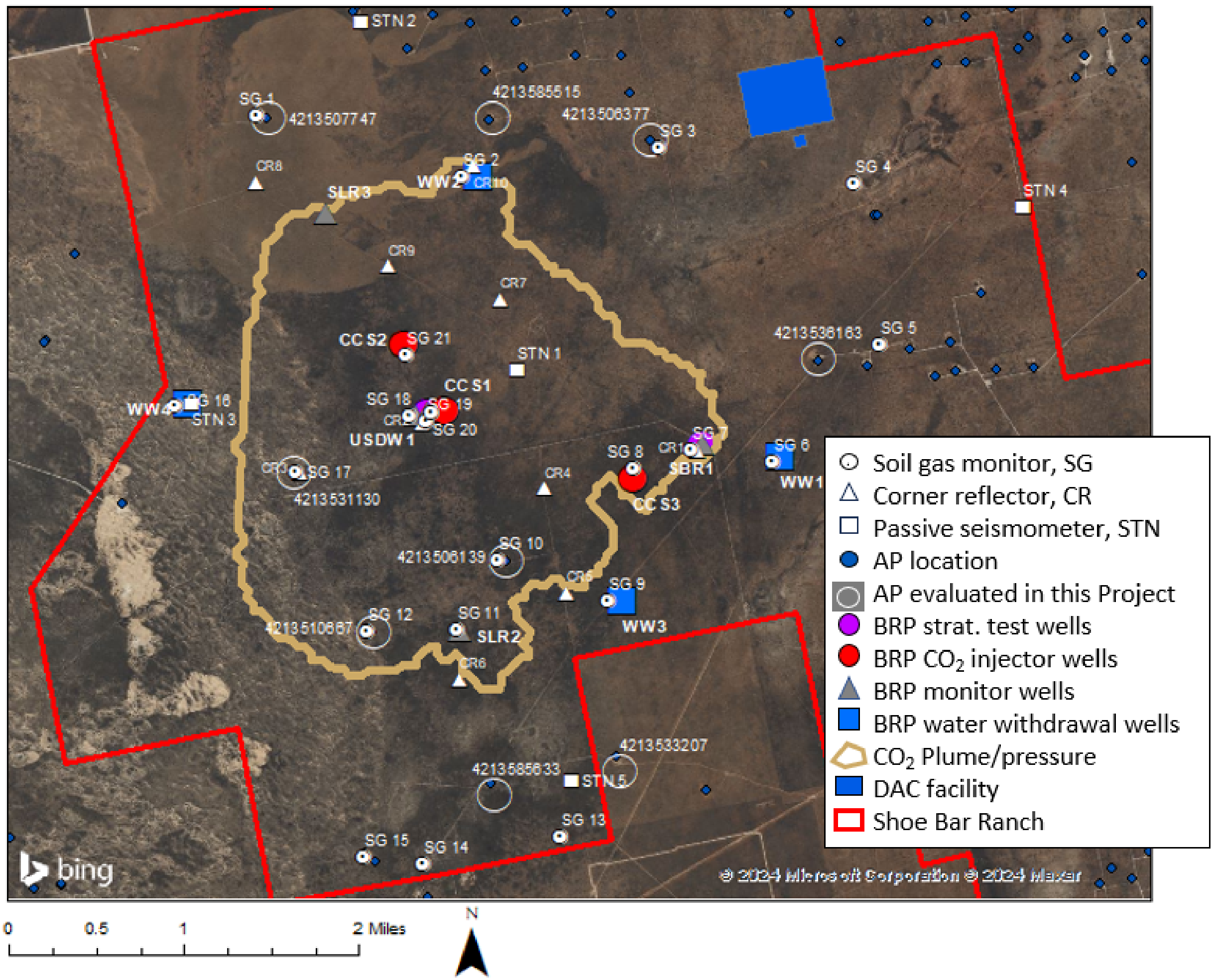

Figure 7—Approximate locations of soil gas monitoring stations and GPS station locations

Soil gas samples at the probe stations will be collected, generally following the procedures set forth in EPA Method SESDPROC-307-R5 (EPA, 2023b), by a qualified and experienced third-party contractor(s). During sample collection, a vacuum will be applied to the tubing on the surface using 60 mL gas-tight syringes, equipped with a 3-way valves, to first purge at least the full length of the tubing, then collect a soil gas sample in appropriate sample containers provided by the laboratories. During soil gas sampling, a leakage test will be conducted by releasing helium gas as a tracer gas within a shroud over each soil gas sampling site. All sample containers will be labeled with a unique sample identification number and sampling date, written with durable labels and indelible markings. The soil and soil gas samples will be preserved appropriately, as required by the specific analytical methods, and shipped within 24 hours of collection to certified laboratories, under chain-of-custody control.

Soil and soil gas sample analyses will be performed by third-party laboratories accredited with the EPA and/or the TCEQ. Operators might audit the procedures and results of the selected laboratories with a third party to review laboratory internal quality control procedures. The samples will be analyzed by a third-party laboratory using standardized procedures for various instruments including gas chromatography, as further described in the QASP.

OLCV personnel experienced in soil analysis and gas composition and isotopic analysis and/or contractors will evaluate the analysis reports provided by the laboratories who analyzed the different samples. These results will be compared with previous measurements to look for trends or changes in chemical composition and distinguish major processes involved in the subsurface which impact the gas composition. The evaluation of soil gas composition and isotopic data will also be coupled with evaluation of other fluids samples, as well as pressure and temperature data to interpret the presence or absence of CO_2 from the Injection Zone or other gases indicated of leakage pathway from the reservoir.

As mentioned in Section 8.1, an anomalous detection of CO_2 above background levels in soil gas “does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists” (EPA, 2013b). Therefore, if a departure from baseline/ seasonal parameter patterns is observed, additional testing of soil gas, the atmosphere, and/or the USDW may be conducted. If OLCV personnel interpret that fluids from the Injection Zone may be leaking into permeable zones above the confining zone and migrated to the vadose zone, the source of the potential leak will be investigated, and appropriate corrective will be taken to protect the drinking water resources within the AoR.

9.0 Internal and External Mechanical Integrity Testing

OLCV will conduct tests to verify the internal and external mechanical integrity of the Injector Wells before and during the injection phase pursuant to 40 CFR §146.89(c), 40 CFR §146.90(e), 40 CFR §146.87 (a)(2)(ii), and 40 CFR §146.87 (a)(3)(ii)].

The purpose of internal mechanical integrity testing is to confirm the absence of significant leakage within the injection tubing, casing, or packers [40 CFR §146.89(a)(1)]. Continuous monitoring of injection pressure, injection rate, injected volume and annulus pressure will be used to ensure internal mechanical integrity. In addition, annulus pressure tests will be periodically conducted to confirm gauge measurements.

The purpose of external mechanical integrity testing is to confirm the absence of significant leakage outside of the casing [(40 CFR §146.89(a)(2))]. OLCV proposes to conduct temperature logging in the Injector wells on an annual basis to demonstrate external mechanical integrity. In addition, OLCV plans to collect continuous temperature profiles above the Injection Zone in Injector wells, using DTS fiber. Based on comparison of results between DTS temperature profiles and temperature logging, OLCV may recommend to the UIC Program Director to cease temperature logging and utilize DTS data only. Ultrasonic tools such as the UltraSonic Imager Tool (USIT^{TM}), or IsoScanner are industry-standard tools that provide information on wellbore integrity. One of these methods will be used to monitor integrity in SLR and WW wells.

9.1 Testing Location and Frequency

Table 15 below provides a summary of the internal and external mechanical integrity monitoring methods and mechanical integrity testing (MIT) plans in the injector and monitoring wells.

To demonstrate internal mechanical integrity of the injector wells, OLCV will perform annular pressure tests during well construction and at least once every five years thereafter, coincident with well maintenance operations in which tubing and packer are pulled. Annular monitoring tests will be performed on SLR and WW wells during construction and annually thereafter. Additional testing will be conducted if the pressure or temperature data collected from gauges or DTS indicates a potential reduction in mechanical integrity.

External mechanical integrity testing on Injector wells will be continuously conducted via DTS fiber and using temperature logging to meet and exceed the requirement of annual testing described in 40 CFR §146.89(c). In addition, at least one type of mechanical integrity log will be conducted during construction of each of the injector wells. Logging will be repeated during well maintenance events to minimize disruption to the injection schedule. If DTS data indicate potential loss of mechanical integrity, this event will trigger acquisition of a mechanical integrity log. SLR and WW wells will also have mechanical integrity testing on an annual basis and logging during construction and once at least every five years thereafter, during subsequent well maintenance. The reporting of mechanical integrity testing will comply with TAC Title 16 Chapter 5.206(e)(1): "The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone."

OLCV engineers will monitor downhole P/T data to look for changes that could indicate leakage inside the annulus or outside of the casing. If anomalous measurements are recorded, OLCV personnel will immediately conduct further investigations to determine if there is evidence of surface leakage and take appropriate corrective action. If no surface leakage is detected, OLCV personnel will continue to evaluate the source of the anomalous data and may choose to conduct an annulus pressure test, wireline conveyed P/T gauge, or other logging tool to investigate the borehole integrity. If anomalous data is not found to be the result of operational changes, such as a rate change, injection operations in the affected well will be ceased until the source of the anomalous data is determined and/or corrective action it applied.

Table 15—Internal and External Mechanical Integrity Monitoring Methods and Frequency in Injector Wells

Internal Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Annular pressure test	During construction and prior to injection	At least once every five years, during well maintenance; and before plugging	NA
DTS	Prior to injection	Continuously	NA
External Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Temperature log	Prior to injection	Annually	NA
DTS	Prior to injection	Continuously	NA

SLR wells will also be monitored for mechanical integrity.

Table 16—Internal and External Mechanical Integrity Monitoring Methods in SLR and WW wells

Internal Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Annular pressure test	Prior to injection	Annually and before plugging	At least once every five years, during workovers; and before plugging
Downhole P/T gauges	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging
External Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Temperature log or other methods: Cement Bond Log (CBL), Variable Density Log, UltraSonic Imager Tool (USIT™), Isolation Scanner™, Electromagnetic Pipe Examiner, Casing Inspection Log	Prior to injection	At least one method once every five years, during well maintenance and before plugging	At least one method once every five years, during workovers; and before plugging

Downhole P/T gauges	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging

9.2 Description of Methods and Justification

9.2.1 Internal Mechanical Integrity Using Annular Pressure Tests

An annular pressure test is a common method to demonstrate internal mechanical integrity. The test is based on the assumption that pressure applied to fluids in the annular space should be constant unless there are significant changes in temperature or a fluid leak.

An overview of the annular pressure test procedure is as follows:

- Shut in the well to stabilize the pressures in the injectors.
- Connect the testing equipment to the annular valves and test surface lines to 1,500 psi above the testing pressure.
- Ensure there are no surface leaks from the pumping unit to the wellhead valve.
- Bleed any air in the system. If needed, fill the annular space with packer fluid and corrosion inhibitor (if so, it should require only a minimal amount).
- Record the initial tubing and casing pressure. The well will be tested to 500 psi in the annular space, and the pressure should not decrease more than 5% in 30 minutes.
- Monitor the tubing and casing pressures continuously. Record the final tubing and casing pressure, then bleed the pressure and volume. If the pressure decreases more than 5%, bleed the pressure, test the surface connection, and repeat the test. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the Program Director.

9.2.2 External Mechanical Integrity Using DTS

OLCV plans to install a fiber optic cable alongside the casing in the Injector wells and secure the cable with clamps. The fiber is connected at the surface to an interrogator that converts the signal to temperature values, and the data are transmitted to the monitoring platform in real time for surveillance purposes. These data can provide high-resolution temperature data that can be used to detect subtle changes in fluid movement in a wellbore. Additional information on DTS technology can be found in the Appendix A of this document.

Based on comparison of DTS data with data obtained via a conventional temperature log, OLCV may recommend to the UIC Program Director that future external mechanical integrity testing be conducted utilizing DTS in lieu of temperature logging.

9.2.3 External Mechanical Integrity Testing Using Logging Tools

OLCV proposes to use an ultrasonic tool such as the Isolation Scanner™, or UltraSonic Imager Tool (USIT™). The tools are readily available technologies on the market and are commonly used to demonstrate external mechanical integrity. These tools may be used to demonstrate mechanical integrity on SLR or WW wells. OLCV may also recommend that these tools be used to demonstrate external mechanical integrity on the Injector wells, following a comparison of results with conventional temperature logging.

In the future, new technologies or tools may be proposed for further discussion with regulators. Additional details on tools can be found in Appendix A of this document.

10.0 Pressure Fall-Off Testing

OLCV will perform a pressure fall-off test prior to injection 40 CFR §146.87(e) and during the injection phase as described below to meet the requirements of 40 CFR §146.90(f).

10.1 Testing Location and Frequency

The table below summarizes the pressure fall-off testing plan for the injector well.

Table 17—Summary of pressure fall-off testing

Method	Pre-Injection	Injection	Post-Injection
Fall-off Testing	Prior to injection	At least once every five years during workovers	N/A

Pressure fall-off testing in the form of Step Rate Test will be conducted upon completion of the injection well to characterize reservoir hydrogeologic properties, aquifer response characteristics, and changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Following the commencement of injection operations, pressure fall-off testing will be conducted at least once every five years during injection and before well plugging. The objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect the well or reservoir performance.

10.2 Description of Methods and Justification

Pressure fall-off testing is a method of monitoring changes that may impact injectivity or pressure response in the near-wellbore environment. Additionally, pressure fall-off testing can be used to monitor wellbore mechanical integrity. The fall-off test is conducted by ceasing injection for a designed time period, and continuously monitoring the pressure and temperature with downhole gauges. The duration of the test is designed to measure the pressure recovery.

Pressure fall-off testing is a proven technology that is widely used in subsurface well operations. The results of pressure fall-off tests will be interpreted by engineers and geologists who are experienced in analyzing this type of data. Experienced senior advisors will be consulted to add additional technical insight. The interpretation will be used to confirm or update operational parameters and confirm wellbore mechanical integrity.

Pressure gauges used to conduct fall-off tests will be calibrated in accordance with the manufacturers' recommendations. In lieu of removing the injection tubing to recalibrate the downhole pressure gauges, their accuracy will be demonstrated by comparison with a second pressure gauge with current certified calibration, which will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves for the downhole gauge, based on annual calibration checks using the second calibrated gauge, can be used for the fall-off test. These calibration curves (showing all historic pressure deviations) will accompany the fall-off test data.

10.3 Interpretation of fall-off test results

Quantitative analysis of the pressure fall-off test response provides the basis for assessing near-well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots measured before CO_2 injection and during the operational injection phases can be used to determine whether significant changes in well or storage reservoir conditions have occurred. Diagnostic derivative plot analysis (Bourdet et al., 1989; Spane, 1993; Spane and Wurstner, 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

Plotting the downhole temperature concurrent with the observed fall-off test pressure is useful to check for anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures are responding differently than registered within the probe sensor), erroneous pressure fall-off response results may be derived. Thus, concurrent plotting of downhole temperature and pressure fall-off responses is useful for assessing whether temperature anomalies may be affecting pressure fall-off recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log-log and semi-log plots of observed pressure change and/or pressure derivative plots vs. recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity) based on characteristic diagnostic falloff pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard et al. (2009).

Early pressure fall-off recovery response corresponds to flow conditions in and near the wellbore, whereas later fall-off recovery response is reflective of reservoir conditions progressively farther from the injection well location. Significant divergence in pressure fall-off response patterns from previous tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure falloff tests for discerning possible changes to well and reservoir conditions is presented by the EPA (2002).

11.0 Carbon Dioxide Plume and Pressure Front Tracking

OLCV will monitor the CO_2 plume and pressure front using both direct and indirect methods pursuant to 40 CFR §146.90(g)(1) and (2). A summary of the methods used for CO_2 and pressure front tracking are provided in Table 18 below.

11.1. Monitoring Location and Frequency

Direct tracking methods include:

- Geochemical monitoring of fluids in the Injection Zone and shallow fluids and gasses. Note that a detailed description of geochemical characterization and monitoring is presented in Section 6 of this document.
- Pressure and temperature measurements from the Injection Zone, and the first permeable layer above the confining zone.

Indirect tracking methods include:

- Estimation of CO_2 saturation using Reservoir Saturation Tool (RST) or Pulsed-Neutron logs (PNL) in SLR2 and SLR3 wells.
- Evaluation of the development and migration pattern of the CO_2 plume and pressure front using time-lapse 2D VSP and 2D surface seismic.
- Calibration of the dynamic simulation model for the AoR re-evaluation.

Table 18—Direct and indirect methods of tracking the CO_2 plume and pressure front

Direct Methods				
Objective	**Method**	**Pre-Injection**	**Injection**	**Post-Injection**
Measure geochemical composition of the Injection Zone	Fluid and dissolved gas sampling in SLR2 and SLR3 wells	During construction and one additional sampling in SLR2	Event-driven*	Event-driven* until plugging
	Fluid and dissolved gas sampling in USDW-level well	Quarterly for at least one year	Quarterly during years 1-3; annually starting in year 4	Annually for first 10 years pending an approved PISC plan
	Fluid sampling in WW wells	Quarterly for approximately one year	Event-driven*	NA
Measure P/T of the Injection Zone	P/T using gauges and/or DTS in SLR2 and SLR3 wells	In SLR2, prior to injection	Continuous	Continuously for the first 10 years pending an approved PISC plan
Indirect Methods				
Objective	**Method**	**Pre-Injection**	**Injection**	**Post-Injection**
Estimate CO_2 saturation in the Injection Zone	PNL or RST in INJ wells	Prior to injection	Event-driven*	NA
	PNL or RST in SLR2 and SLR3 wells	In SLR2, prior to injection	Annually	Annually until plugging
	PNL or RST in WW wells	Prior to injection	Once every five-year period	NA
Estimate CO_2 plume and pressure extent in the Injection Zone	2D VSP in INJ wells	Prior to injection	2D VSP at years 1, 2, 5 and 10	NA
	2D VSP in selected SLR wells	Prior to injection at SLR2	2D VSP in year 5 or 10	Once approximately every five-year period until plugging or plume stabilization
	2D surface seismic	Prior to injection	Year 10	Once approximately every five-year period until plume stabilization
	DInSAR with GPS	Prior to injection	Quarterly	Annually for five years or until plume stabilizes
	Computational modeling	Prior to injection	As needed, to be used for AoR re-evaluation	As needed, to be used for AoR re-evaluation

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

11.2 Description of Methods and Justification

The direct and indirect tracking methods described in this document meet and/or exceed the requirements of the Testing and Monitoring plan established in UIC Class VI. The proposed methods are proven technologies and have been used by the Operator to safely conduct subsurface operations for decades. Additional new technologies will be considered in a cost versus benefit analysis and added to the plan if they are deemed to be warranted.

11.2.1 Geochemical Monitoring

Geochemical monitoring will be employed in SLR2, SLR3 and USDW monitoring well. These data will be compared with the pre-injection geochemical and isotopic characterization to constrain whether changes are observed. If changes are measured, then OLCV will constrain whether the compositional changes are likely to be the result of naturally occurring biological processes or another source. Additional details on geochemical monitoring are described in Section 6 of this document.

11.2.2 Pressure and Temperature Monitoring

Pressure and temperature gauges will be deployed on the tubing above and below the injection packer to monitor bottomhole conditions in real time. In SLR2 and SLR3 wells, the gauges and cables will be selected to withstand CO_2 service conditions. These data will be integrated in the SCADA system and surveillance platform. OLCV will routinely evaluate the data and interpret the results. If a change in pressure or temperature is recorded, OLCV will evaluate and attribute the source of the change. Additional details on downhole gauge instrumentation are described in the QASP document that is part of this application.

The SLR1 well also contains DTS and DAS fiber for monitoring pressure and temperature. However, the fiber was damaged near the top of the Injection Zone. The fiber may provide pressure and temperature data on shallower zones including the Upper Confining Zone, and it may be used for collecting VSP data.

11.2.3 Saturation Detection Tool Method

Reservoir saturation tool (RST) / pulsed neutron logs (PNL) will be run through the tubing to detect changes in CO_2 saturation and identify potential breakthrough of the plume. The pulsed neutron log is considered a proven technique to detect gas saturation in reservoirs. Advances in the technology have improved the accuracy of the tool for tracking movement of CO_2 plumes in the reservoir and evaluating flow conformance. Details of the saturation log / pulsed neutron technique are described in Appendix A to the Testing and Monitoring Plan.

OLCV plans to collect saturation logs in SLR2 and SLR3 wells on a yearly basis. These measurements will provide a record to track potential changes in fluid over time in the Injection Zone. To help calibrate data from the Injection Zone, saturation logs will also be collected in the Injector wells once every five years. The first permeable zone above the confining zone is not expected to encounter any CO_2 from injection. A saturation log may be conducted in the SLR1 and ACZ1 to monitor above the confining zone approximately once every five years.

11.2.4 Repeat Seismic Methods

Baseline seismic acquisition

2D and 3D surface seismic was collected in 2022 for use in site characterization, and as pre-injection baseline of the BRP site. The 3D was acquired in an area of approximately 20 mi^2 and extends approximately one mile beyond the anticipated CO_2 and pressure plumes. Approximately 10 miles of 2D surface seismic was acquired. The survey was designed with a high density of sources and receivers to image from the near-surface down to basement. Vibroseis was used as the source for the acquisition. The processing sequence included pre-processing, pre-stack depth migration and velocity model building, followed by post-migration processing.

Justification of time-lapse seismic methods

OLCV integrated the results of the 2D and 3D seismic with rock and fluid properties measured in the Shoe Bar 1 (SLR1) and Shoe Bar 1AZ (ACZ1) to screen for detectability of a geophysical response resulting from a change in fluid or pressure in the Injection Zone. Figure 8 shows a forward model based on the Shoe Bar 1AZ that demonstrates the geophysical response resulting from a 20% CO_2 saturation in porous (>8p.u.) zones over a ~500 ft thick carbonate as described in Figure 8. This screening result demonstrates the subtlety of time-lapse changes to sonic and density logs in the Injection Zone.

The detectability of a change in fluid or pressure is improved by utilizing wellbore seismic methods, therefore OLCV proposes to acquire seismic using a Vertical Seismic Profile (VSP) in wellbores. Modeling conducted by OLCV indicates that 2D VSP is an appropriate seismic method. Because of the low dip on the Injection and Confining Zone units, 3D VSP is not modeled to yield a significant advantage over 2D VSP, and therefore 2D VSP is proposed for this study.

The imaging area of a VSP is limited to ~3500 – 3800 feet away from the wellbore, based on modeling conducted by OLCV and a third-party contractor. To image the full extent of the AoR, OLCV proposes to acquire 2D surface seismic in a radial pattern centered near the surface location of the injector wells. For surface methods, the detectability of a time-lapse response resulting from a change in fluid or pressure improves with higher concentrations of CO_2. Therefore, surface seismic will be used as a monitoring technique in the later part of the Injection Phase and in the PISC.

[redacted]

Figure 8—Example of forward modeled seismic response resulting from 20% CO_2 saturation at Shoe Bar 1AZ. Model shows a significant low impedance shift compared to the brine saturated base case.

Timing of baseline and repeat seismic acquisition

Following drilling and prior to commencement of injection, a 2D VSP baseline will be acquired in the Injector wells. The Injector wells are designed to contain DAS fiber to the top of the Injection Zone. OLCV may also collect baseline 2D VSP in the SLR1 and SLR2 monitoring wells, utilizing DAS fiber. Additional monitoring wells drilled in the future may also be equipped with DAS. In event that DAS fails, or if a VSP will be collected in a well without DAS, a borehole geophone array can be deployed for data acquisition.

Baseline surface 2D seismic will be acquired in a radial pattern around the wells, concurrent with baseline VSP survey acquisition. The acquisition will be conducted using conventional Vibroseis vehicles and/or Surface Orbital Vibroseis (SOV). The surface acquisition will be dense to improve imaging from throughout the stratigraphic column from surface to basement.

Following the commencement of injection, time-lapse 2D VSP surveys will be conducted in the Injector wells and in SLR2 at approximately 12 months and 24 months following commencement of injection. The purpose of these surveys is to provide high-resolution, early indicators of plume orientation. The timing of future VSP acquisition will be planned to provide information for AoR re-evaluation, at approximately five and 10 years after the start of injection.

Repeat surface 2D is planned to occur at approximately year 10 following the commencement of injection. Based on the detectability and resolvability observed with this survey, 2D surface acquisition may continue throughout the PISC at an interval of approximately once every five years, or until plume stabilization.

If data collected with other monitoring methods indicates a significant deviation of the plume from the modeled forecast, seismic may be acquired at a more frequent interval. Figure 9 shows the anticipated extent of VSP imaging and notional survey design.

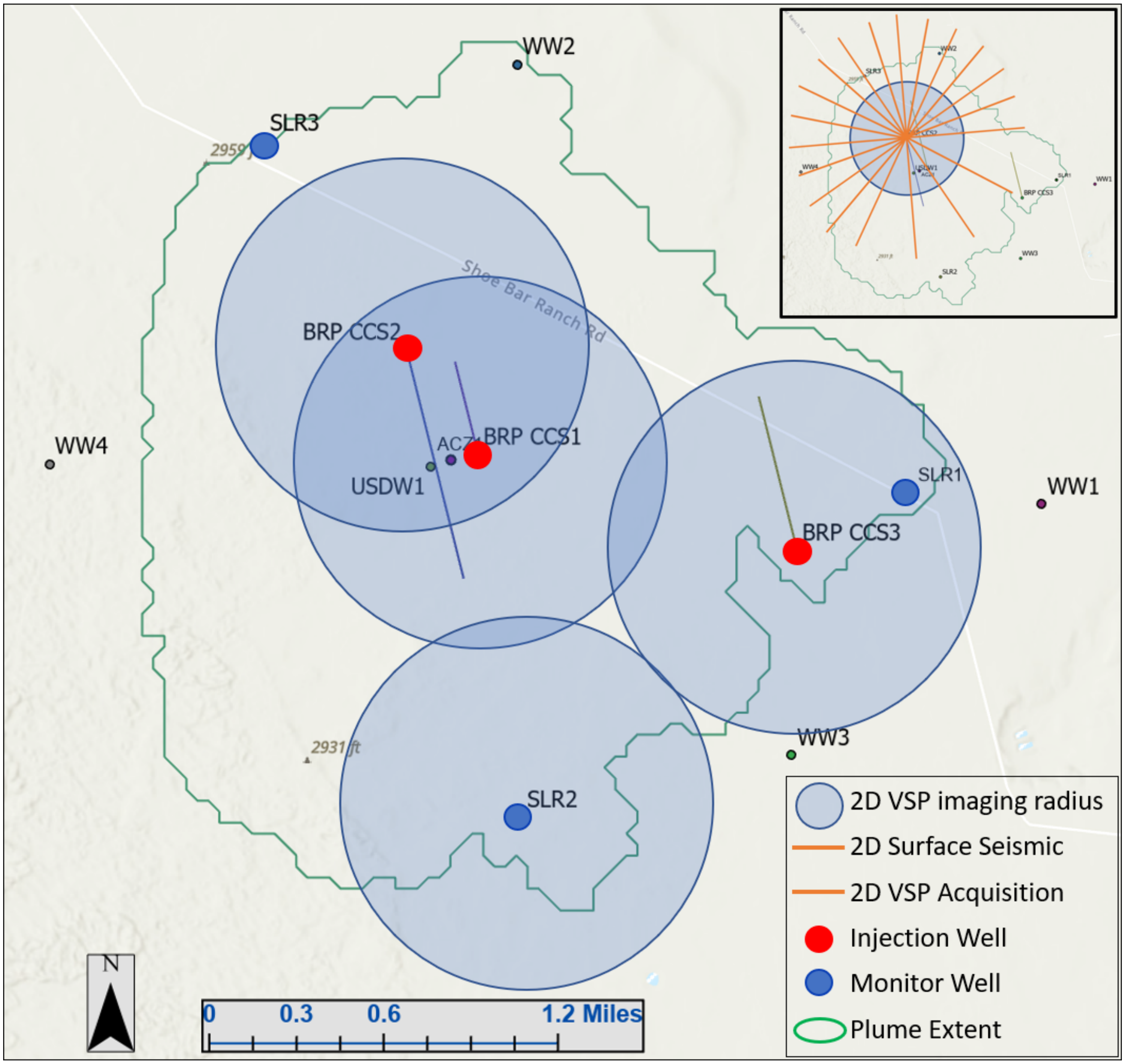

Figure 9—The extent of the 2D VSP imaging area (blue circles). The inset map shows an idealized survey design for 2D surface seismic (orange lines) with 2D VSP acquisition. The maximum distance between two open 2D lines is ~800ft for VSP and ~1,200ft for surface seismic.

New and emerging technologies

OLCV will re-evaluate new and improving time-lapse monitoring techniques, such as a Scalable, Automated, Sparse Seismic Array (SASSA), at least every five years and will recommend changes to the monitoring plan if these technologies are interpreted to provide improved monitoring results. Recommendations will be reviewed with the UIC Program Director.

11.2.5 DInSAR and GPS data acquisition

The BRP Project plans to use Differential Interferometric Synthetic-Aperture Radar (DInSAR) and Global Positioning Systems (GPS) data to indirectly monitor the position of the CO_2 pressure plume. DInSAR is a non-intrusive, non-destructive technology that measures, with high accuracy, relative displacement over time. It is highly effective for measuring ground deformation over multiple years. A network of 10 "corner reflectors" will be installed by a third-party contractor to serve as permanent monuments to aid in data processing repeatability. Prior to injection a historical evaluation of past ground movement will be conducted. These data will be licensed from a third-party DInSAR contractor and interpreted by the contractor and by qualified Oxy and OLCV personnel.

To further improve the resolution and accuracy of DInSAR, BRP plans to install a local geodetic network of GPS stations to provide a common space-temporal reference frame for all geodetic and geophysical surveys in the area. For this study area, approximately 10 stations will be placed in a regularly-spaced array. Each station typically consists of a four-inch pipe installed at a depth of 5-11 feet. Stations will be installed by a third-party contractor. Data will be processed by qualified Oxy or OLCV personnel or by third-party contractors.

DInSAR coupled with GPS technology provides sub-millimeter ground surface deformation data that informs the following interpretations:

- Surface impact caused by subsidence or uplift induced by Injection Zone operations.
- Calibration of geomechanical models by providing information on the mechanical properties of the Injection and Confining Zones.
- Monitoring of the stress field depth.
- Identification of potential leakage pathways.

Table 19 below describes the sampling and recording frequency for DInSAR and GPS data. See Figure 7 for the planned locations of corner reflectors.

Table 19—Summary of DInSAR and GPS sampling plans

Objective	Method	Minimum sampling frequency	Minimum recording frequency
Measure surface displacement	DInSAR	Quarterly	Image recording bi-weekly
	GPS	Quarterly	Quarterly

11.2.6 Dynamic simulation modeling

A dynamic simulation model has been constructed and is used to inform the interpretation of the AoR. This model will be evaluated after the commencement on injection operations and calibrated to operational data. The model will be updated, as needed, to meet the requirements of 40 CFR §146.84(e) that require AoR re-evaluation on a fixed frequency not to exceed five years. The frequency of model updates will be dependent on the amount of deviation from the predicted plume and pressure front.

Dynamic simulation modeling is used to predict changes in the Injection and Confining zones over time. OLCV first constructed a static geocellular model using log, core, and seismic data from the site. Stratigraphic tops were selected on well logs and then mapped throughout the field to form a stratigraphic framework. The framework was divided into geologic zones and assigned rock and fluid properties derived from log and core analysis. The static geomodel forms the basis for the reservoir simulation model.

OLCV constructed a dynamic simulation model that tracks the composition of brine and CO_2 through time. Following the commencement of injection operations, the predictions made on CO_2 and pressure front movement will be calibrated with direct and indirect plume and pressure tracking data. These data will be used to history match the dynamic model and then update forecasts of plume and pressure movement in the future. Significant deviation from forecasts will lead to updates to the AoR delineation. See additional information on delineation of the AoR in the AoR and Corrective Action Plan that is part of this application.

11.2.7 Interpretation and Analysis of Data Collected

The data collected with direct and indirect tracking methods will be evaluated by subsurface geologists and engineers. In addition, OLCV will utilize senior technical advisors to review work products and provide additional technical insight. Data will be routinely reviewed and integrated into and updated subsurface characterization that will be used to inform the AoR and future testing and monitoring plans.

12. Induced Seismicity Monitoring

12.1 Description of Methods and Justification

12.1.1 Traffic Light System for Monitoring Induced Seismicity

Based on information provided by the United States Geological Survey (USGS), the BRP Project area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex. Seismicity history is discussed in more detail in the Area of Review and Corrective Action Plan document of the permit.

Change of in-situ stresses on existing faults caused by human activities (e.g., mining, dam impoundment, geothermal reservoir stimulation, wastewater injection, hydraulic fracturing, and CO_2 sequestration) may induce earthquakes on critically stressed fault segments. To monitor potential induced seismicity due to the injection of CO_2 in the area, it is proposed that the project deploy surface seismometer stations.

While the historical seismicity of the project area indicates no earthquakes in the immediate vicinity, the operator intends to monitor the site with a seismic monitoring system for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. The seismic monitoring will be conducted with a surface array deployed to ensure detection of events above local magnitude (ML) 1.0, with epicentral locations within 10 miles of the injection well.

If an event is recorded by either the local private array or a public (national or state) array occurs within 10 miles of the injection well, OLCV will implement the response plan subject to detected earthquake magnitude limits defined below to eliminate or reduce the magnitude and/or frequency of seismic events:

- For events above ML 2.0 but below ML 3.5 within 5.6 miles of the injection wells, OLCV will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity. The 5.6 mile radius is used because this is the metric used for disposal well applications to the Railroad Commission. "Pursuant to 16 Texas Administrative Code §3.9(3)(B) and §3.46(b)(1)(C), SWD well permit applications must include a review of USGS earthquake records for a circular area of 100 square miles around the proposed SWD well location (a circular area with a radius of 9.08 kilometers, or 5.64 miles)."
- For events with ML 3.5 to ML 4.5 within 5.6 miles of the injection well, OLCV will initiate contact with relevant regulatory and/or government entities. OLCV will begin a technical review within 24 hours of the event to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include, but not limited to:
    1. Reducing CO_2 injection pressures until reservoir pressures fall below a critical limit.
    2. Increasing water production rates until reservoir pressures fall below a critical limit
    3. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.
        - OLCV will obtain approval from the relevant regulatory and/or government entities to implement revised plan.

    - If the event is not related to the storage facility operation, OLCV will resume normal injection rates.

- For events above ML 4.5 within 5.6 miles of the injection well, OLCV will stop injection as soon as safely practical. OLCV will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. OLCV will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis will be conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  1. Reducing injection pressures until reservoir pressures fall below a critical limit.
  2. Increasing water production rates until reservoir pressures fall below a critical limit.
  3. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.
     - OLCV will obtain approval from the relevant regulatory and/or government entities to implement a revised plan.
     - If the event is not related to the storage facility operation, and with prior approval from the regulators, OLCV will adjust injection and/or production rates to previous rates in steps, while increasing the surveillance.

12.1.2 Induced Seismicity Monitoring Network

Presently, the nearest seismometers to the AoR are part of the MTX and TexNet arrays. The USGS seismometer network in Texas is known as TexNet. The MTX array is a private subscription array. Oxy has been a subscriber to MTX since its inception in 2017. Together, the data from the TexNet and MTX arrays provide accurate seismicity information throughout the Permian Basin.

OLCV plans to install five additional seismometers delivering real-time seismicity alerts within the BRP Project area. To achieve the lowest magnitude of completeness within the AOR, modeling is ongoing to identify optimal locations to site the new seismometers. Installation is expected mid-2024. The data from seismometers installed for the purposes of the BRP Project are not intended to be publicly available.

A seismometer monitoring network will be deployed to determine the locations, magnitudes, and focal mechanisms of any injection-induced seismic events in case they occur. This information will be used to address public concerns and to monitor changes in induced seismicity risks with a goal of reacting to the perceived risk through adjustment of well operations as needed.

A map of proposed new station locations is provided in Figure 10 (and also Figure 7). Existing locations are provided as attachment in the GSDT. These station locations were used for modeling the expected sensitivity of the array at the project site. Locations are subject to change in order to optimize the station locations around surface infrastructure and access limitation and changes to the pressure plume modeled so as to provide optimum monitoring of the site.

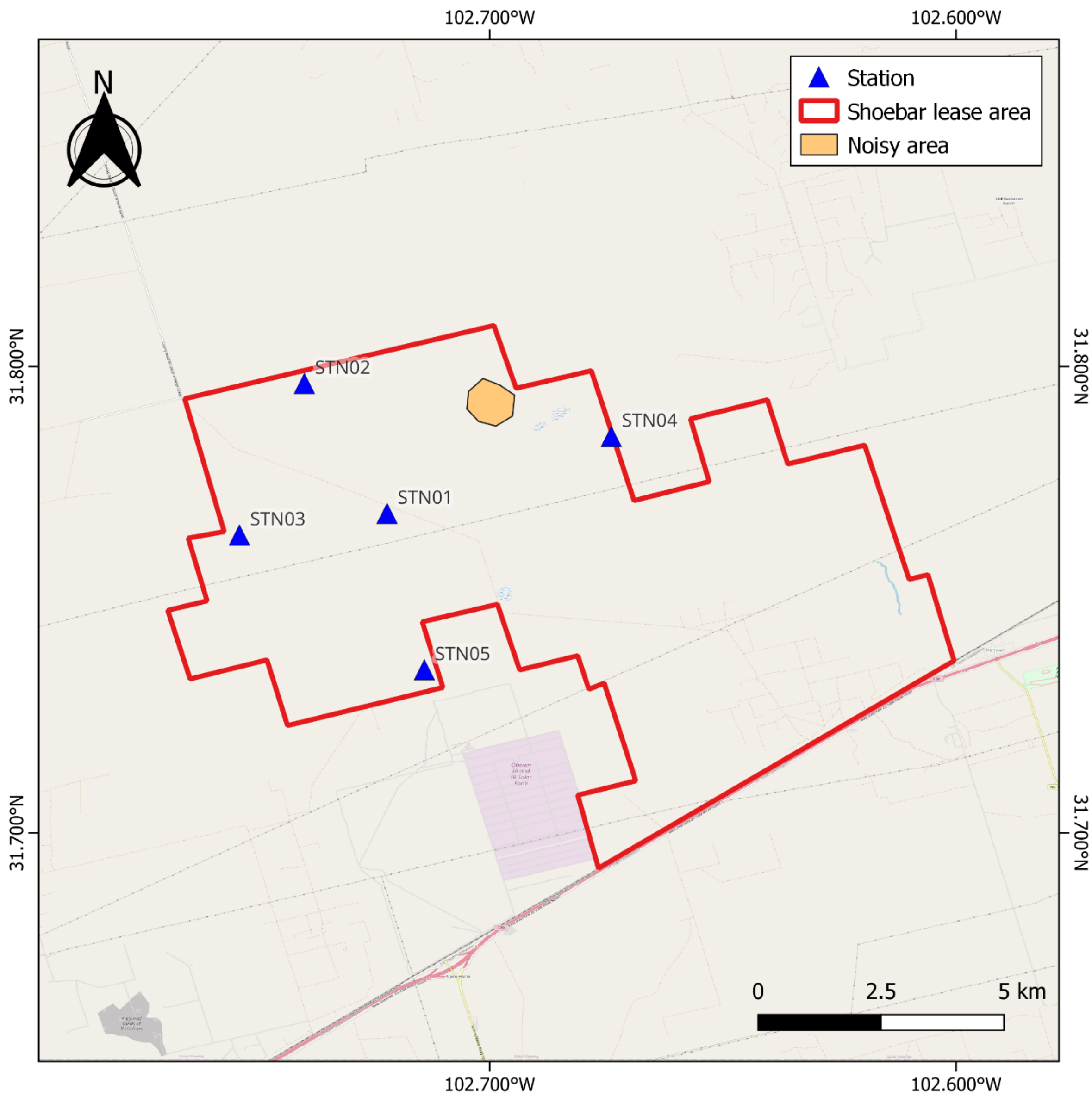

Figure 10—Locations of proposed new passive seismic monitoring stations

The design and installation of the station array is performed by specialized contractors and include the following activities:

- Project management support to design the seismometer array, model the network performance, coordinate permitting and equipment installation, conduct testing and maintenance, and ensure optimum execution of the Project.
- Field operations to deploy seismic station instrumentation, run power and communication systems, monitor data quality, and do commissioning.
- Data acquisition, system configuration, and process setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst reviews and alert notifications, for events at or above predetermined magnitude thresholds over the seismic area.

12.1.3 Seismicity Monitoring Equipment

The equipment proposed for seismicity monitoring includes: broadband sensors, a data logger, a solar power system and backup battery, communication system, cabling, and mounting equipment (Figure 11).

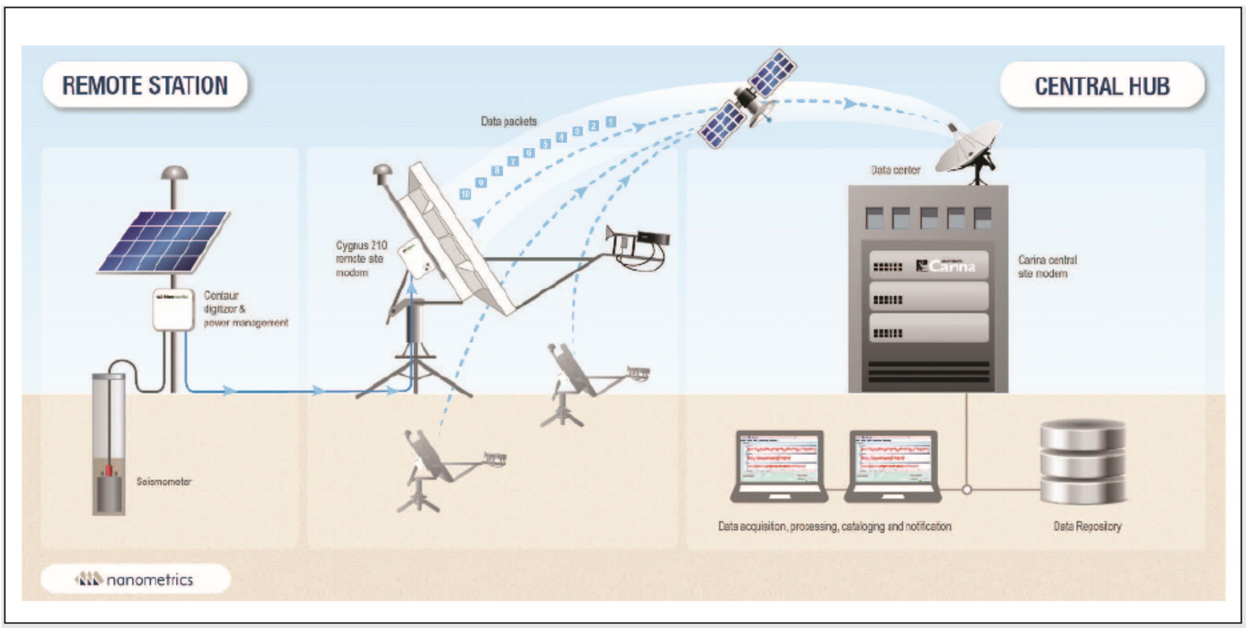

Figure 11—Example of a setup for data acquisition, transfer, storage, and analysis.

13.0 Reporting

The results of all testing and monitoring are to be described in a semi-annual report that will be submitted to the EPA.

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