TESTING AND MONITORING PLAN
40 CFR 146.90

RUSSELL CO_2 CAPTURE AND SEQUESTRATION

Facility Information

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List of Acronyms and Abbreviations

2D = two-dimensional
3D = three-dimensional
Ag = Silver
Al = Aluminum
ANSS = Advanced National Seismic System
AoR = area of review
AQMS = ANSS Quake Monitoring System
As = Arsenic
ASTM = ASTM International
AVO = audio, visual, and olfactory
B = Boron
Ba = Barium
bbl = barrels
Be = Beryllium
bpd = barrels per day
Br = Bromide
BSL = below surface level
Ca = Calcium
$CaCO_3$ = Calcium carbonate
Cd = Cadmium
CDP = common depth point
Cl = Chloride
Co = Cobalt
CO_2 = carbon dioxide
Cr = Chromium
Cu = Copper
$d^{13}C$ of DIC = Ratio of two stable carbon isotopes in dissolved inorganic carbon
DIP = Attribute measuring the angle at which a planar feature is inclined to the horizontal feature
DTS = distributed temperature sensor
ELAP = Environmental Laboratory Accreditation Program
F = Fluoride
Fe = Iron
ft = feet
ft/min = feet per minute
ft/s = feet per second
ft/s^2 = feet per second squared
ft bgs = feet below ground surface
gal = gallon(s)
GS = geologic sequestration
MD = measured depth
Mg = Magnesium
mi^2 = square mile(s)
MIT = mechanical integrity test
M_L = local magnitude
MMA = maximum monitoring area
Mn = Manganese
ms = millisecond
N = Nitrogen
Na = Sodium
NACE = NACE International
NDVI = normalized difference vegetation index
Ni = Nickel
NO_3 = Nitrate
Pb = Lead
PCC = PureField Carbon Capture, LLC
PISC = Post-Injection Site Care
ppmv = parts per million by volume
psi = pound-force per square inch
psia = pound-force per square inch, absolute
psig = pound-force per square inch, gauge
QASP = Quality Assurance and Surveillance Plan
QC = quality control
RGT = Relative Geological Time
RMS = Root Mean Square
SAS = Seismic Action Score
Sb = Antimony
Se = Selenium
Si = Silicon
SiO_2 = Silicon dioxide
SM = Standard Method
SO_2 = sulfur dioxide
SO_4 = Sulfate
sq. mi. = square mile
Sr = Strontium
TAR = True Amplitude Recovery
TEG = triethylene glycol
Tl = Thallium
UIC = Underground Injection Control
US = United States
US EPA = United States Environmental

GPSA = Gas Processors Supplier Association
GUI = graphical user interface
H_2S = hydrogen sulfide
IARF = Infinite-acting radial flow
ICP = Inductively coupled plasma
ICP-MS = Inductively coupled plasma mass spectrometry
K = Kelvin
KARS = Kansas Applied Remote Sensing
KCC = Kansas Corporation Commission
KDHE = Kansas Department of Health and Environment
KGS = Kansas Geological Survey
lb = pound(s)
lbmol = pound mole(s)
Li - Lithium
Protection Agency
USDW = Underground Source of Drinking Water
USGS = United States Geological Survey
V = Vanadium
Zn = Zinc

E.1. Summary

This Testing and Monitoring Plan describes how PureField Carbon Capture, LLC (PCC) will monitor the Russell carbon dioxide (CO_2) Storage Complex site pursuant to 40 CFR 146.90. In addition to demonstrating the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to Underground Source of Drinking Water (USDW). The monitoring data will also be used to validate and adjust the geological 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.

The plan is designed with a suite of methods covering:

- Well Integrity – An integrated set of testing and monitoring elements are utilized to assure mechanical integrity for the geologic sequestration (GS) project wells.
- Operational Testing and Monitoring During Injection – A comprehensive program consisting of: Analysis of CO_2 Stream, Monitoring of Operational Parameters, Corrosion Monitoring, and Pressure Fall-Off Testing.
- Groundwater Quality and Geochemical Monitoring – A series of monitoring stations have been established across the project site to support testing of groundwater quality and geochemical monitoring of groundwater key locations above the primary upper confining zone.
- Plume and Pressure Front Tracking – Plume tracking is performed by direct measurements on injection zone fluid samples from MW #1, plus indirect geophysical measurements using time-lapse surface seismic surveys across the GS project site. Pressure front tracking is performed by direct measurement of downhole pressures at CSS #1 and MW #1, plus indirect geophysical measurements using micro-seismic event tracking across the GS project site.
- Additional Testing and Monitoring – Implementation of Soil Gas Monitoring, Ecosystem Stress Monitoring, and Surface CO_2 Monitoring programs to improve the ability to detect potential leaks of CO_2 to surface, plus implementation of a Seismic Monitoring program for timely detection of induced and/or natural seismic activity.

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

E.2. Overall Strategy and Approach for Testing and Monitoring

The overall strategy and approach for testing and monitoring is to utilize a comprehensive set of test methods to obtain the data needed to monitor the GS project per the requirements of 40 CFR 146.90, demonstrate non-endangerment to USDWs, and provide sufficient data on site-specific system behavior to support decision making at project milestones.

Figure E.2-1 is a simplified illustration showing how potential project risks vary over the course of a GS project, along with a summary timeline for testing and monitoring activities during the GS project periods. All testing and monitoring activities in this plan apply to the Injection period of the project. The pressure differential in some portions of the injection zone is above the minimum threshold pressure differential needed to force fluids into the lowermost USDW, thus project risk is comparatively high during the Injection period. This plan also covers several testing and monitoring activities that begin prior to the Injection period in order to obtain baseline data needed for interpretation of data collected during later periods (e.g., data on groundwater quality above the upper confining zone); however, see the Pre-Operational Testing Program for descriptions of logging and testing of CSS #1 and MW #1 that occur prior to the Injection period.

This plan also covers testing and monitoring activities that extend into the Post-Injection Site Care (PISC) period when project risk begins to fall. To simplify discussion on frequency of testing and monitoring during PISC, the PISC period will be divided into: (a) an Initial PISC period during which time the frequency of testing and monitoring will be carried over from the Injection period since project risk remains relatively high, and (b) a Maintenance PISC period starting at the end of the Initial PISC period and ending at Site Closure during which time the types and frequency of testing and monitoring can be reduced since project risk is comparatively low. Subdividing the PISC period into an Initial PISC and a Maintenance PISC period follows EPA recommendations in Section 3.3 of the EPA PISC and Site Closure guidance document (EPA 2016). The quantitative criterion used to define the transition from Initial-to-Maintenance PISC is when the CSS #1 pressure differential during post-injection falls below 100 psi; at this point in time, the pressure differential everywhere within the injection zone is well below the minimum threshold pressure differential needed to force fluids upward into the lowermost USDW. Setting the transition to occur at a CSS #1 pressure differential of 100 psi provides a sufficient safety factor to ensure project risks have been mitigated prior to reduced monitoring during the Maintenance PISC period. Section B.3.3 of the Area of Review and Corrective Action Plan shows the computational model predicts the transition between the Initial PISC and Maintenance PISC periods will occur two years after cessation of injection.

Figure E.2-1. Testing and Monitoring Activities During Different Periods of a GS Project in Relation to Potential Project Risk
(From: EPA 2013)

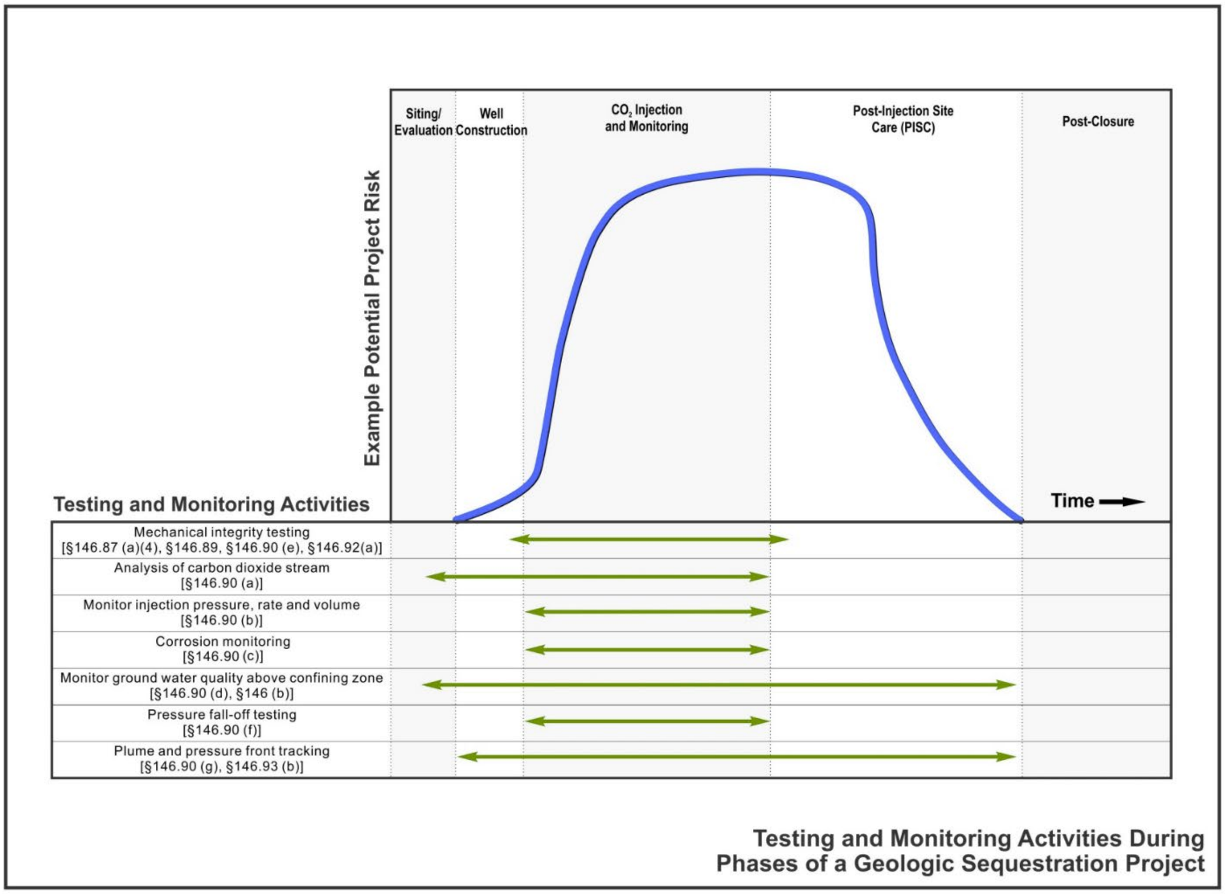


Table E.2-1 provides a summary of the testing and monitoring plan by category/sub-category along with a general schedule for each test method. A primary test method is given for each sub-category that directly addresses the requirements of 40 CFR 146.90. In addition, the plan is designed with a suite of complementary methods. Analyses of data from these complementary methods are used to corroborate analysis results from the primary test method and/or provide redundancy in the event of a primary test method failure.

Table E.2-1. Summary of Testing and Monitoring Plan

Category	Parameter	Location	Primary Test Method					Complementary Methods
			Testing Frequency by Project Period				Method	
			Pre-Injection	Injection	Initial PISC	Maintenance PISC		
Well Integrity	Internal Mechanical Integrity	CSS #1	Not Applicable	Continuous	Not Applicable	Not Applicable	Monitoring of Operational Parameters	1) Annulus Pressure Test 2) Corrosion Monitoring
		CSS #1	Once	Every 5 years	Every 5 years until internals removal	Every 5 years until internals removal	Annulus Pressure Test	1) Monitoring of Operational Parameters 2) Corrosion Monitoring
	External Mechanical Integrity	CSS #1, MW #1	Baseline Temperature Log	Annual	Annual	Every 5 years	Oxygen activation log, Temperature log, or Noise log	1) Monitoring of Operational Parameters 2) Corrosion Monitoring
Operational Testing and Monitoring During Injection	Analysis of CO_2 Stream	CSS #1	Not Applicable	Chemical: Quarterly, Isotope: Every 5 yr	Not Applicable	Not Applicable	Laboratory analysis of grab samples	Monitoring of Operational Parameters
	Monitoring of Operational Parameters	CSS #1	Not Applicable	Continuous	Not Applicable	Not Applicable	Measurement of CO_2 parameters (pressure, temperature, flow, density, composition); plus measurement of annulus pressure and fluid added	Automatic alarms and shut-down systems
	Corrosion Monitoring	CSS #1	Not Applicable	Quarterly	Not Applicable	Not Applicable	Corrosion coupon testing	1) Internal Mechanical Integrity 2) External Mechanical Integrity
	Pressure Fall-Off	CSS #1	Once	Every 5 years	Not Applicable	Not Applicable	Pressure fall-off test	Monitoring of Operational Parameters

Category	Parameter	Location	Primary Test Method					Complementary Methods
			Testing Frequency by Project Period				Method	
			Pre-Injection	Injection	Initial PISC	Maintenance PISC		
Groundwater Quality and Geochemical Monitoring	Groundwater Quality	MMA	Continuous	Continuous	Continuous	Data Logger Only	Monitor network of above upper confining zone groundwater wells	Geochemical & isotope analyses of groundwater samples
	Geochemical Monitoring	MMA	Annual	Annual	Annual	Every 5 years	Geochemical & isotope analyses of groundwater samples	Monitor network of above upper confining zone groundwater wells
Plume and Pressure Front Tracking	Plume Tracking (Direct)	MW #1 (lower zone)	Annual	See Testing & Monitoring Plan text	Not Applicable	Not Applicable	Geochemical & isotope analyses of injection zone fluid samples	Computational modeling
	Plume Tracking (Indirect)	MMA	One 3D survey (baseline)	Every 5 years, plus one at end of period	Not Applicable	Every 5 years from start of PISC, plus one at end of period	Time lapse 2D/3D surface seismic surveys	Computational modeling
	Pressure Front Tracking (Direct)	CSS #1	Continuous (upon installation)	Continuous	Continuous	Continuous (Data Logger Only)	Downhole pressure measurements	Computational modeling
		MW #1 (lower zone)	Continuous (upon installation)	Continuous	Continuous	Continuous (Data Logger Only)	Downhole pressure measurements	Computational modeling
	Pressure Front Tracking (Indirect)	MMA	Continuous (upon installation)	Continuous	Continuous	Not Applicable	Micro-seismic event tracking	Computational modeling

Category	Parameter	Location	Primary Test Method					Complementary Methods
			Testing Frequency by Project Phase				Method	
			Pre-Injection	Injection	Initial PISC	Maintenance PISC		
Additional Project-Specific Testing & Monitoring	Soil Gas Monitoring	MMA	Continuous	Continuous	Continuous	Data Logger Only	Monitor soil gas CO_2 across station network	1) Lab analysis of samples from station network 2) CO_2 efflux measurement at each station
			Annual	Annual	Annual	Every 5 years	Lab analysis of samples from station network	1) Monitor soil gas CO_2 across station network 2) CO_2 efflux measurement at each station
			Annual	Annual	Annual	Every 5 years	CO_2 efflux measurement at each station	1) Monitor soil gas CO_2 station network 2) Lab analysis of samples from station network
	Ecosystem Stress Monitoring	MMA	Annual	Annual	Annual	Not Applicable	Remote sensing by satellite	1) Groundwater monitoring 2) Soil gas monitoring
	Surface CO_2 Monitoring	CSS #1, MW #1	Not Applicable	Continuous	Continuous	Data Logger Only	Atmospheric CO_2 sensor at wellhead	AVO Inspection of wellhead and surface piping
		CSS #1	Not Applicable	Quarterly	Not Applicable	Not Applicable	AVO Inspection of wellhead and surface piping	Atmospheric CO_2 sensor at wellhead
	Seismic Monitoring	MMA	Continuous, to establish baseline	Continuous	Continuous	Not Applicable	Micro-seismic event tracking	Seismic event tracking using regional networks
			Continuous	Continuous	Continuous	Continuous	Seismic event tracking using regional networks	Micro-seismic event tracking

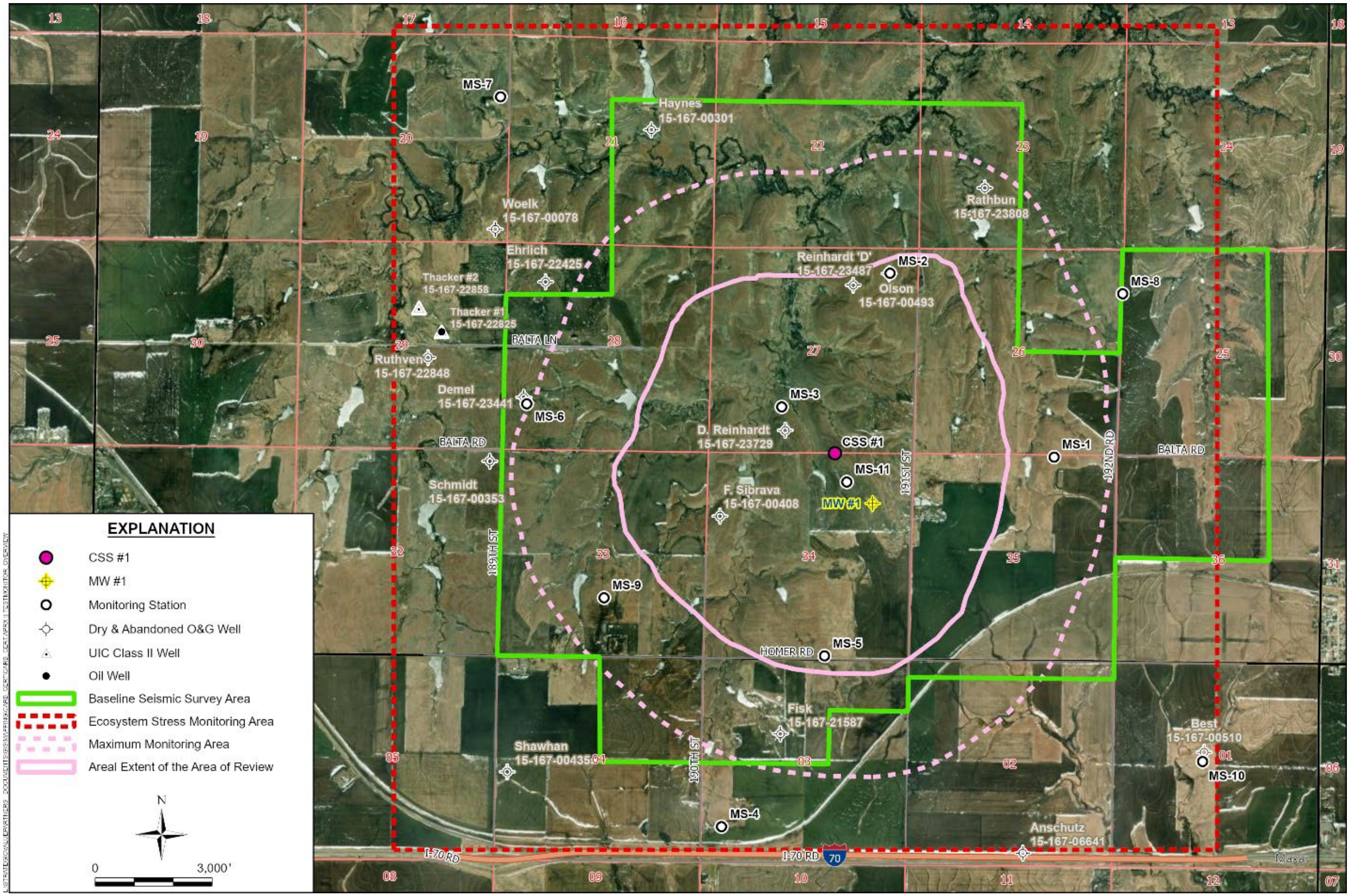
2D = two-dimensional
3D = three-dimensional
MMA = maximum monitoring area
Continuous = ranges from every 2 seconds to every 30 minutes depending upon sampling and recording frequencies of the specific monitoring system

The general schedule is designed to provide testing and monitoring results in a timely manner, while being judicious in the need to interrupt operations during the Injection period. The ethanol plant producing the CO_2 source undergoes an annual scheduled maintenance outage for several days each year during which time CO_2 is not available for injection. This testing and monitoring plan is designed around this annual scheduled CO_2 supply outage. The injection well may either be shut-in or undergo a workover during the annual scheduled CO_2 supply outage; thus scheduling of testing and monitoring activities conveniently falls into the following categories:

- Continuous, monthly, and quarterly testing and monitoring activities are performed at the indicated frequency, independent of the schedule for well shut-ins or workovers since all of these activities can be performed without interrupting injection operations;
- Annual and 5-year testing and monitoring activities that require a well shut-in or workover are performed during the annual scheduled CO_2 supply outage; or
- Annual and 5-year testing and monitoring activities that do not require a well shut-in or workover are performed at the indicated frequency, independent of the schedule for well shut-ins or workovers since all of these activities can be performed without interrupting injection operations.

The spatial distribution of this plan covers the three-dimensional volume of the AoR as delineated in the Area of Review and Corrective Action Plan. In addition, this plan covers the maximum monitoring area (MMA), where the MMA is defined as the areal extent of the AoR plus a ½-mile buffer zone. Figure E.2-2 is a surface map that displays the areal extent of the AoR, the MMA, and the extent of testing and monitoring.

Figure E.2-2. Predicted AoR/MMA Boundaries and Testing and Monitoring Extent



This plan is tailored to the regional and local site characterization and risk profile of this particular GS project. The testing and monitoring requirements of 40 CFR 146.90 result in a complementary suite of methods that address most aspects needed to verify a GS project is operating as permitted and is not endangering USDWs. However, a site-specific risk assessment for this GS project identified CO_2 leakage to the surface and induced/natural seismic events as scenarios not fully addressed by the minimum requirements of 40 CFR 146.90. Thus, this plan contains additional testing and monitoring elements to identify and quantify potential CO_2 leakage to the surface across the MMA (i.e., Soil Gas Monitoring, Ecosystem Stress Monitoring, Surface Air Monitoring), and this plan also contains a Seismic Monitoring program to identify and mitigate risks associated with both local micro-seismic events and larger regional seismic events.

E.2.1. Quality Assurance Procedures

The Quality Assurance and Surveillance Plan (QASP) provided as Attachment E.I of the Testing and Monitoring Plan includes and describes the project-specific quality assurance procedures to be followed pursuant to 40 CFR 146.90(k).

E.2.2. Reporting Procedures

PCC will report the results of all testing and monitoring activities to the United States Environmental Protection Agency (US EPA) in compliance with the requirements set forth under 40 CFR 146.91. See Section A.III.3 of Summary of Requirements for further discussion of reporting items, reporting methods, and reporting timing and frequency.

E.3. Internal Mechanical Integrity [40 CFR 146.87(a)(4)(i), 40 CFR 146.90(b)]

An annulus pressure test (aka tubing-casing annulus pressure test) will be conducted on CSS #1 during the Pre-Injection period to confirm internal mechanical integrity in conformance with 40 CFR 146.87(a)(4)(i). This Pre-Injection period test will be conducted after the well has been constructed and all well logs have been conducted.

Monitoring of operational parameters (see Section E.6) is the primary method to ensure internal mechanical integrity of CSS #1 during the Injection period, conforming to the requirements of 40 CFR 146.90(b). In addition, PCC will conduct annulus pressure tests to further confirm internal mechanical integrity during the Injection period: 1) at least once every 5-years, or 2) after every workover that has the potential to compromise the internal mechanical integrity of the well including but not limited to the downhole replacement of tubing and safety valves. PCC intends to work with the US EPA UIC program to re-permit CSS #1 as a monitoring well during PISC in accordance with Class VI rules and regulations. PCC will extend annulus pressure testing into the PISC period at the same frequency adopted for the Injection period, until such time as the internals of CSS #1 are removed.

A standard annulus pressure test procedure will be followed patterned off the procedure provided by the US EPA (Attachment 1 – Standard Annulus Pressure Test, in EPA 2008). In summary, the steps are:

1. The annulus will be filled with liquid and the temperature along the entire length of the tubing (as measured by the distributed temperature sensor [DTS] system) will be allowed to stabilize either by a well shut-in or maintaining stabilized injection before and during the test (i.e., continuous injection at a constant rate and constant injection fluid temperature).
2. After temperature stabilization, the annulus will be pressurized to a surface pressure of 2,000 psig, which greatly exceeds the minimum requirement of 110% times the sum of the anticipated maximum operating pressure of the internal tubing at wellhead plus 100 pounds per square inch (psi) to account for the minimum pressure difference between the annulus and internal tubing during normal injection operations. Once pressurized for this test, the annular system will be isolated from the source of pressure and any sources of additional liquid.
3. The annulus system must remain isolated for a testing period of no less than 60 minutes unless a shorter time is deemed adequate upon completion of the final system design. Pressure measurements will be recorded at 5-minute intervals during isolation unless a different interval is deemed acceptable upon completion of the final design.
4. After the test is completed, the valve to the annulus should be opened and liquid flow from the annulus observed and measured using a graduated bucket/tank.

Two techniques will be utilized to validate test results per Attachment 1 – Standard Annulus Pressure Test in EPA 2008, both of which are summarized below:

<u>Pressure Change:</u> The annulus pressure test is considered successful if the pressure change is 3% (test pressure x 0.03) or less during the test period

<u>Volume of Liquid Returned:</u> The volume of liquid returned at the conclusion of the test should be near the anticipated volume calculated by the formula:

$$dV = (P_t - P_f) * V_f * h * 0.0000032$$

where

dV = the amount returned, gals
P_t = the pressure used to test the annulus, psig
P_f = annulus pressure after depressurization, psig
V_f = the volume of one foot of the annulus from Halliburton table 221-B, gals
h = length of the annulus, ft
and 0.0000032 represents compressibility of water, gal/gal/psi

For a valid test, several gallons of liquid should be returned and the difference between the measured and calculated volumes should be small.

E.4. External Mechanical Integrity [40 CFR 146.87(a)(4), 40 CFR 146.89(c), 40 CFR 146.90(e)]

PCC will conduct at least one of the external mechanical integrity tests (MITs) presented in Table E.4-1 periodically to verify external mechanical integrity of CSS #1 over its service life as required at 146.87(a)(4), 146.89(c), and 146.90. In addition, these same tests and testing frequency will be utilized to verify external mechanical integrity of MW #1 over its service life even though the Class VI regulations do not strictly require external mechanical integrity testing for monitoring wells.

Table E.4-1. External MIT Summary

Test Description	Tool Type
Oxygen Activation Log	Wireline
Temperature Log	DTS or Wireline
Noise Log	Wireline

The DTS systems are planned to be the primary tool for external MIT at both CSS #1 and MW #1. A wireline log (e.g., oxygen activation, temperature, noise) may be run to further investigate an anomaly found by a functioning DTS system, where an anomaly is defined as a temperature variance of greater than 10% of the anticipated temperature that is not associated with a change in operating conditions. Section H.4.1 of the Emergency and Remedial Response Plan provides the response to be taken upon discovery that an anomaly is confirmed to be caused by a loss of mechanical integrity. Wireline logs may also be run in the event of a malfunction in one of the DTS systems. Non-emergency situations resulting in the use of a wireline tool (e.g., an anomaly attributable to something other than a MIT failure, malfunction of a DTS system) will be reported to EPA via the regular periodic reports listed in Section A.III.3 of the Summary of Requirements.

E.4.1. Testing Location and Frequency

The frequency of testing for CSS #1 and MW #1 will be: at least once during Pre-Injection, annual during Injection, annual during the Initial PISC period, and once every five years during the Maintenance PISC period. Testing for CSS #1 will occur during planned shut-ins or workovers and will utilize the DTS (preferred) or any of the other methods identified in Table E.4-1. Testing for MW #1 will occur at the indicated frequency and will utilize the DTS (preferred) or any of the other methods identified in Table E.4-1. The Pre-Injection tests will use a temperature log in order to provide a baseline for comparison with any future temperature logs taken during Injection or PISC periods.

E.4.2. Testing Details

Pass/fail results from external MITs conducted on CSS #1 will be corroborated with analysis of the Monitoring of Operational Parameters data (annulus fluid pressure, annulus fluid volume added) and data from the Corrosion Monitoring program. Pass/fail results from external MITs conducted on MW #1 will be corroborated with data from the Corrosion Monitoring program.

E.4.2.1. Oxygen Activation Log

An oxygen activation log is based on the ability of a wireline tool to emit high-energy neutrons that penetrate the casing and cement, converting the oxygen in water molecules outside the wellbore into N^{16} – an unstable isotope of nitrogen that undergoes beta decay with a half-life of 7.1 seconds, and generating high-energy gamma rays during beta decay of N^{16}. The resulting gamma rays easily re-penetrate the casing and cement and are measured by gamma ray detectors in the wireline tool, thus allowing the measurement of the direction and speed of water movement around the outside of the casing. An oxygen activation log can be conducted on a well using a wireline tool if the internals are removed, or on a well containing tubing using a slimline tool provided any injection is occurring close to the normal rate and there are minimal rate and pressure fluctuations during logging.

The tool is to be calibrated and operated per the recommendations of the service provider and tool manufacturer. A calibration report will be provided with every log that provides details on methods and results. While calibration details will vary between service providers and tool manufacturers, discussions with one service provider found their tool is initially calibrated in the shop prior to deployment using a large water tank to measure neutrons (sigma) within a controlled environment per tool manufacturer recommendations and API standards. Their calibration step is a calibration log in the well, which typically involves conducting a baseline gamma ray log and casing collar locator log from the top of the injection zone to the surface to determine naturally occurring background radiation, then taking a stationary measurement in a "no vertical flow behind the casing" section to zero the instrument.

At a minimum, stationary readings will be taken after the logging tool reaches each of the targeted intervals for measured depth (MD) at CSS #1 designated below and allowed to stabilize for at least 15 minutes:

- Base of the lowermost USDW – 533' MD
- Top of the regional seal – 2,910' MD
- Tops of secondary upper confining zones – 3,095' MD, 3,116' MD
- Top of the primary upper confining zone – 3,282 ' MD, 3,337' MD

A potential loss of external mechanical integrity is indicated when the gamma ray measurements detect a difference between the expected (static) and measured gamma ray count rate profiles. The flow velocity is determined by measuring the time that activated water passes by a detector.

External mechanical integrity is indicated when measured water speed at all locations are below a threshold of 2 feet/minute (ft/min) (Attachment 7, in EPA 2008). To minimize false positives, all measurement locations that indicate a water flow equal to or greater than 2 ft/min will be confirmed by measurements at several nearby depths (within 50 feet of original stationary location) and/or confirmed by measurements at the original stationary location under a minimum of 3 varying injections rates: 75%, 50%, and 25% of the maximum permitted injection rate (Attachment 7, in EPA 2008). Any failure in external MIT indicated by an oxygen activation log will be further confirmed using another approved external MIT method prior to taking measures to remedy the situation.

See the Reservoir Saturation Tool entry of Table E.I.1-14 in the QASP for detailed information on the oxygen activated logging tool and its measurement specifications (e.g., range, precision, spatial resolution).

E.4.2.2. Temperature Log

A temperature log for external MIT purposes is based on the principle that fluid leaking from the well bore will cause a temperature anomaly in the formation adjacent to the well bore since the leaking fluid will, in most cases, be of a different temperature compared to native fluids at a given depth. Temperature logging for external MIT purposes during the Injection period are run after the well has been shut-in to allow for temperature equilibration. The US EPA (EPA 2013) states that 36 hours is usually a sufficient shut-in period for temperatures within the well bore to move toward static geothermal conditions. If there has been a leak of fluid out of the well, the temperature within the well bore at this location will be measured as an anomaly because the temperature of the surrounding formation will have been modified by the leaking fluid.

CSS #1 is equipped with a continuously monitored DTS fiber optic system connected to the outside of the injection tubing. During normal injection operations, the DTS system can provide temperature measurements along the length of the tubing that are mostly representative of the temperature of the CO_2 stream. However, when the well is shut-in, the DTS provides temperature measurements that are representative of the formation temperature due to conductive heat transfer from the formation into the annulus fluid. Alternatively, a continuously moving wireline tool can be used to carry out the temperature log measurements.

MW #1 is equipped with a continuously monitored DTS fiber optic system cemented to the outside of the casing, thus the DTS provides temperature measurements representative of the formation. Alternatively, a continuously moving wireline tool can be used to carry out the temperature log measurements.

Temperature logs for both CSS #1 and MW #1 will be conducted prior to start of injection to establish baseline static geothermal conditions. These baseline logs will be conducted long after drilling of the wells since temperature effects due to circulation and infiltration of drilling fluid can persist for several weeks or months after drilling is complete (EPA 2013).

Figure E.4-1 illustrates a static geothermal temperature profile, with comparison to a hypothetical example of a temperature log taken on an operating well after a 36-hour shut-in period. The anomaly in the temperature log of this hypothetical example aligns with the location of the casing leak.

Figure E.4-1. Temperature Log Showing the Detection of a Casing Leak

Hypothetical Example, Not to Scale (From: EPA 2013)

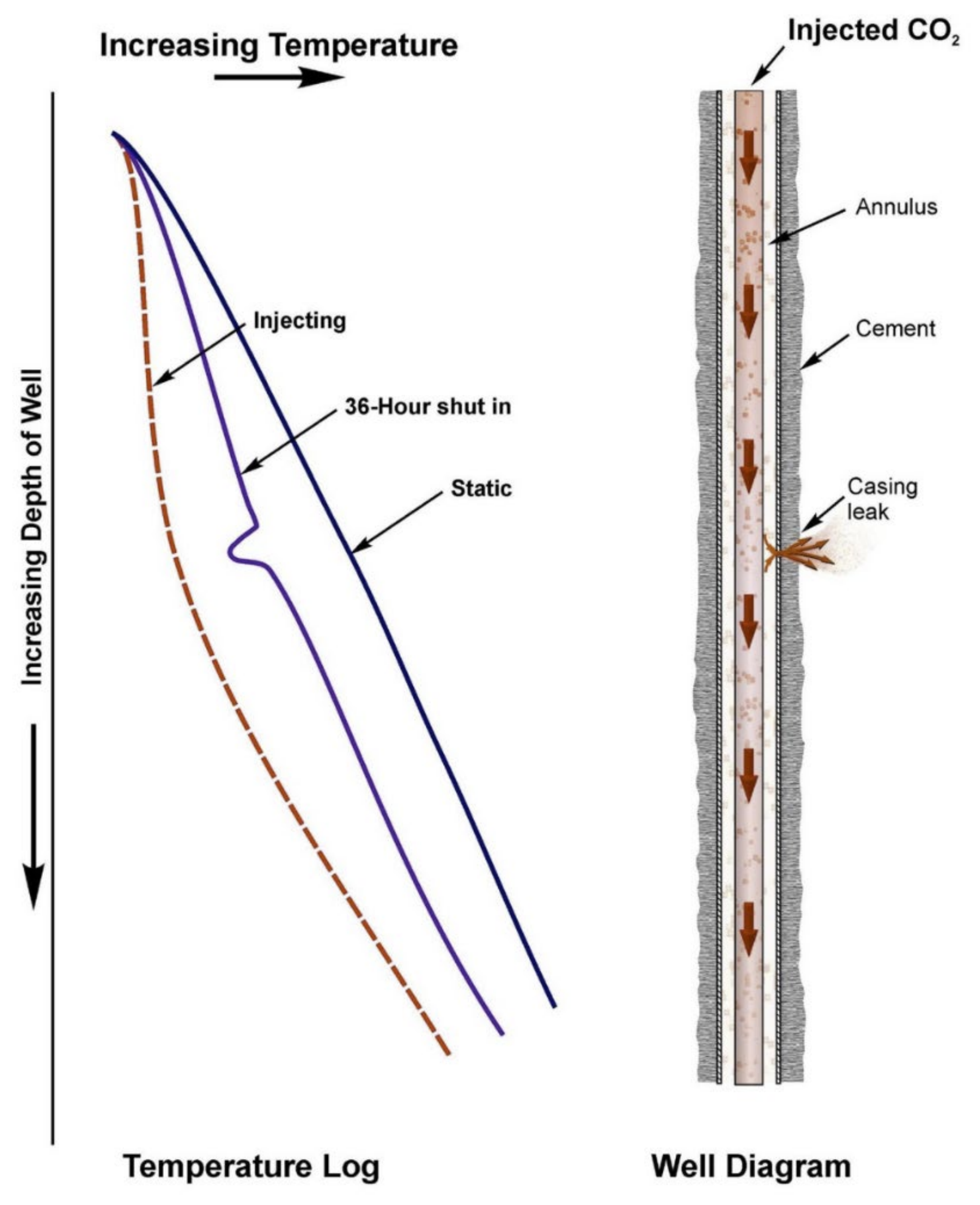


Table E.4-2 provides measurement intervals for external MIT by temperature logs.

Table E.4-2. External MIT Measurement Intervals for Temperature Logs

Well	Measurement Interval	
	DTS	Wireline
CSS #1	3,530' MD - Surface Data collected every 5'	3,400' MD - Surface Data collected every 1'
MW #1	3,683' MD - Surface Data collected every 5'	3,400' MD - Surface Data collected every 1'

See Section E.I.1.4 of the QASP for detailed information on the temperature logging tool and its measurement specifications (e.g., range, precision, spatial resolution).

E.4.2.3. Noise Log

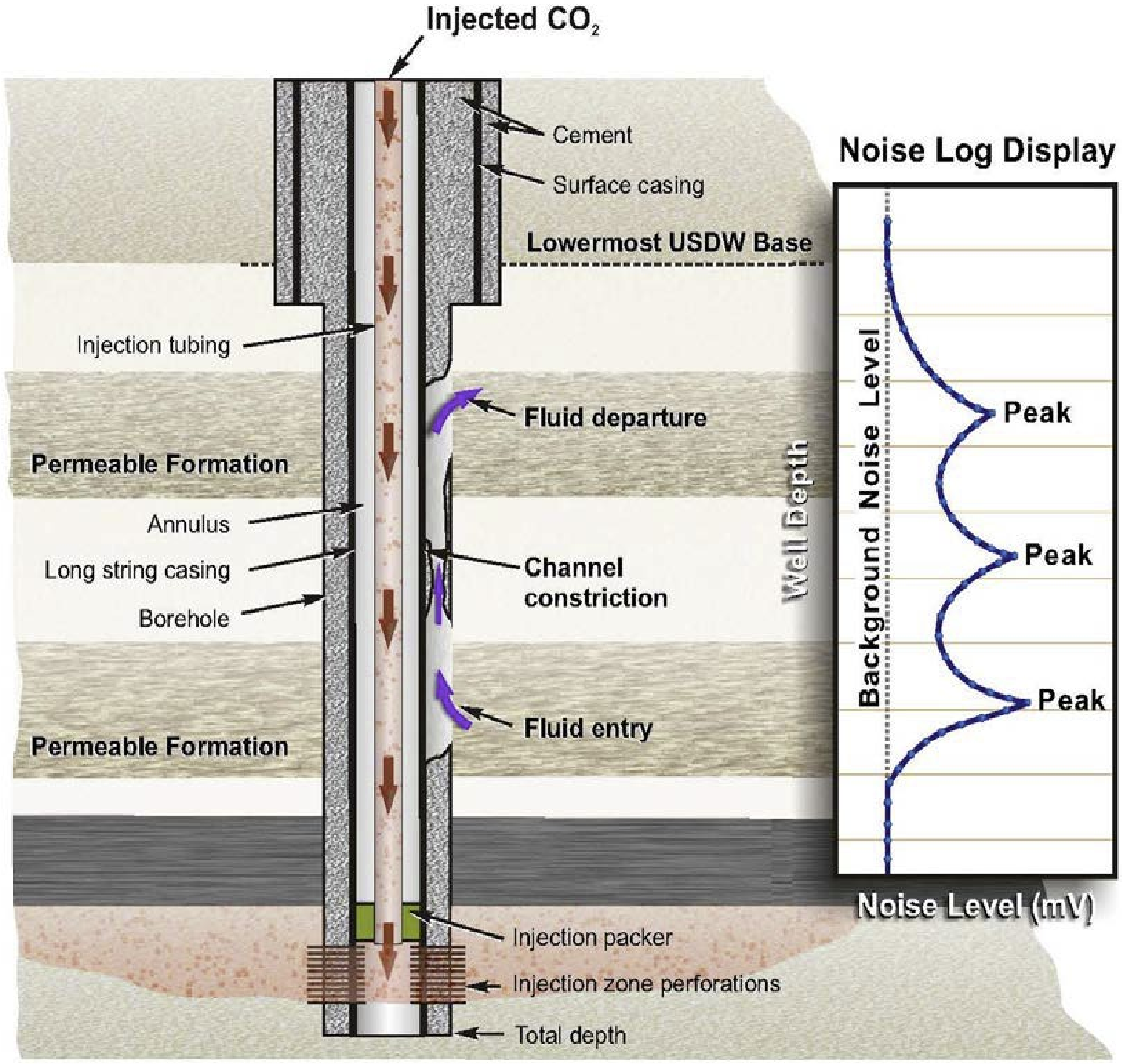
A noise log utilizes the principle that fluid flowing through channels in cement along the exterior of a wellbore usually results in the generation of some turbulence, creating sonic energy in audible frequency ranges that can be measured using a wireline tool containing very sensitive microphones, see Figure E.4-2. Noise logging can be conducted on a well with tubing using a slimline tool, and the log can be conducted while injecting.

Noise log measurements are done in stationary mode. A reconnaissance mode can be used to identify general locations with higher-than-expected noise levels, followed by a series of stationary measurements to identify the exact location of the sonic energy. The US EPA recommendation for measurement intervals will be followed, starting with a coarse grid of measurements at 100-foot intervals, followed by 20-foot intervals within any coarse grid intervals containing high noise levels (EPA 2013). Also, measurements will be made at 10-foot intervals through the first 50 feet above the injection interval and at 20-foot intervals within 100 feet above that zone, and at 20-foot intervals within the base of the lowermost USDW.

Interpretation of noise logs requires establishment of a baseline noise level, with departures from baseline noise levels indicating an anomaly potentially associated with loss of external mechanical integrity. The threshold noise level indicating an anomaly will be set following recommendations of the service provider and equipment manufacturer. Any failure in external MIT indicated by a noise log will be further confirmed using another approved external MIT method prior to taking measures to remedy the situation.

See Section E.I.1.4 of the QASP for detailed information on the noise logging tool and its measurement specifications (e.g., range, precision, spatial resolution).

Figure E.4-2. Noise Log Showing Detection of Fluid Flow in Cement Channels
Hypothetical Example, Not to Scale (From EPA 2013)



E.5. Analysis of CO_2 Stream [40 CFR 146.90(a)]

PCC 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).

E.5.1. Sampling Location and Frequency

PCC will sample the CO_2 stream during the Injection period and test the samples via laboratory analyses. This sampling and testing will occur in addition to the continuous measurement and recording of the chemical composition of the CO_2 stream as described in Section E.6 Monitoring of Operational Parameters.

Table E.5-1. Summary of CO_2 Stream Sampling Location and Frequency

Parameter	Sampling Location	Project Period	Frequency
Chemical Composition	Immediately upstream of injection flow meter	Pre-Injection	Not Applicable
		Injection	Quarterly
		PISC	Not Applicable
Isotope Concentration	Immediately upstream of injection flow meter	Pre-Injection	Not Applicable
		Injection	Every 5 Years
		PISC	Not Applicable

Note: A change in the CO_2 source would trigger an unscheduled isotope sampling event. Such a change would also entail a permit revision as discussed in Section A.1 of the Application Narrative

Table E.5-1 summarizes sampling location and frequency. Grab samples for laboratory analysis will be taken during the Injection period from the sample port integrated in the sample station hardware for AN-0501, which is located immediately upstream the injection flow meter FE-0505 and is in close proximity to CSS #1 in conformance with the sample location requirements of 40 CFR 98.444(b)(3) – see the engineering schematic of the above ground equipment for CSS #1 provided as Figure A.II.2-3 in Section A.II.2.2.2 of Well Construction Details. Sampling and testing for chemical analysis will occur quarterly per the requirements of 40 CFR 146.90(a) and 40 CFR 98.444(b)(3). Sampling and testing for isotope analysis will occur once every five years. No sampling will occur during the Pre-Injection or PISC periods since the CO_2 stream is not available during these periods.

The CO_2 stream is nearly pure CO_2 (> 99%). The source is CO_2-rich fermentation off gases that have been water washed to reduce traces of ethanol and other volatile organic compounds – see Section A.1 of Application Narrative for further elaboration of the CO_2 source and the CO_2 capture and processing steps upstream of the injection well CSS #1. PureField Ingredients, LLC (parent company of PCC) has regularly measured the chemical composition of this CO_2 source as part of its air emissions testing and reporting program – see summary of past testing results in Section A.7.2 of Application Narrative. The data show the chemical composition has been consistent over time. Major constituents are reported as CO_2 and water, plus low levels of nitrogen and oxygen that were likely the result of air contamination introduced during sampling.

Trace constituents are reported as ethanol plus minor levels of other volatile organic compounds. Additional testing for other species of potential interest found an absence of hydrogen, carbon monoxide, methane and other higher hydrocarbons, hydrogen sulfide (H_2S), and sulfur dioxide (SO_2); if present, the concentrations of these species were below the detection limits of the test methods utilized (ASTM International [ASTM] D1945, ASTM D6228).

Table E.5-2 presents the expected chemical composition of the injectate. The concentration of water vapor is the main difference between the expected composition and the results from past chemical testing. Prior air emissions testing work sampled the source gas leaving the fermentation off gas scrubber, which is water saturated at the pressure and temperature at the top of the scrubber, whereas the sample station in this test plan is located near the injection well downstream of the new surface equipment for compression and dehydration. This new surface equipment includes a triethylene glycol (TEG) dehydration skid designed to remove water vapor to 15 pounds per million standard cubic feet (316 parts per million by volume[ppmv]) or less in the CO_2 stream.

Table E.5-2. Expected Chemical Composition of Injectate

Constituent	Concentration
Carbon Dioxide	> 99% volume (dry)
Nitrogen	< 0.5% volume (dry)
Oxygen	< 0.5% volume (dry)
Water	< 400 ppmv
Ethanol	< 100 ppmv
Other VOCs	< 50 ppmv total

PCC will also obtain isotope data for CO_2 stream during the Injection period. These data will be used for any investigations during the Injection and PISC periods of the project in the event that elevated concentrations of CO_2 are found in soil gas monitoring samples. The analytes and test methods used for isotope analysis of the CO_2 stream duplicate those for the soil gas monitoring samples.

E.5.2. Analytical Parameters

PCC will analyze the CO_2 for the constituents identified in Table E.5-3 using the methods listed.

Table E.5-3. Summary of Analytical Parameters for CO_2 Stream

Analyte	Analytical Methods[1]
Carbon Dioxide	ASTM D1946, ASTM D1945, GPA 2261, GPA 2177, ASTM E1747, EPA Method 3/3C, ISBT 2.0, or similar
Nitrogen	ASTM D1946, ASTM D1945, GPA 2261, GPA 2177, ASTM E1747, EPA Method 3/3C, ISBT 4.0, or similar
Oxygen	ASTM D1946, ASTM D1945, GPA 2261, GPA 2177, ASTM E1747, EPA Method 3/3C, ISBT 4.0, or similar
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry by method SRI 8610C[2]

Note 1: An equivalent method may be employed with the prior approval of the Underground Injection Control (UIC) Program Director
Note 2: Gas evaluation technique by Atekwana and Krishnamurthy 1998, with modifications made by Hackley et al. 2007
$\delta^{13}C$ of DIC = ratio of two stable carbon isotopes in dissolved inorganic carbon

E.5.2.1. Sampling Methods

Representative samples will be taken at the designated sample station using materials, equipment, and procedures given in Section E.I.2.2.a/b of the QASP.

E.5.2.2. Laboratory to be Used/Chain of Custody and Analysis Procedures

Sample analysis will be conducted by a qualified outside laboratory using procedures described Sections E.I.2.3 and E.I.2.4 in the QASP.

E.6. Monitoring of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

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

E.6.1. Monitoring Location and Frequency

PCC will perform the activities identified in Table E.6-1 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies described in the table. Section A.II.2.2.2 of Well Construction Details contains a schematic of above ground equipment and instruments for CSS #1. Section E.I.2.10 of the QASP provides details on data management.

Table E.6-1. Sampling Devices, Locations, and Frequencies for Continuous Monitoring of CSS #1

PureField may elect to sample and record more frequently than shown in this table

Parameter	Device(s)	Location	Active Operation, Min Frequency	
			Sampling	Recording
CO_2 Pressure	PT-0501A	Surface – Immediately upstream of injection flow meter	2 sec	1 min
CO_2 Pressure	PT-0503	Surface - Wellhead tubing	2 sec	1 min
CO_2 Pressure	PT-0505	Downhole - Proximate to packer	2 sec	1 min
CO_2 Temperature	TE-0501	Surface – Immediately upstream of injection flow meter	2 sec	1 min
CO_2 Temperature	TE-0503	Surface - Wellhead temperature	2 sec	1 min
CO_2 Temperature	TE-0505	Downhole - Proximate to packer	2 sec	1 min
CO_2 Mass Flow Rate	FE-0501	Surface – From injection flow meter	2 sec	1 min
CO_2 Density	DE-0501	Surface – From injection flow meter	2 sec	1 min
CO_2 Composition	AN-0501	Surface – Immediately upstream of injection flow meter	2 sec	1 min
Annular Pressure	PT-0504	Surface – Wellhead annulus	2 sec	1 min
Annulus Fluid Volume	LT-0501	Surface – Annulus Fluid Tank level	2 sec	1 min

Notes:

• Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.

• Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

E.6.2. Monitoring Details

Section E.I.2.7 of the QASP provides details on the operational instruments (e.g., calibration standards, precisions, and tolerances) and supporting information on the measurements and calculations.

CO_2 amounts can be measured and reported on either a mass or volumetric basis. In general, CO_2 amounts will be reported in this project on a mass basis using the unit of metric tons. Reported CO_2 amounts are from instantaneous or cumulative measurements made by the injection flow meter, which is a Coriolis meter that directly measures mass flow rates. Metric ton is the preferred unit as it is most widely used for government reporting (e.g., annual cumulative mass flow is typically reported in metric ton/year).

CO_2 amounts will occasionally be reported on a volumetric basis. Unless otherwise stated, CO_2 volumes will be reported as standard volumes in barrels (bbl) referenced to the standard density of pure CO_2 at saturation pressure and 60 °F since this convention is widely used in the United States (US) oil & gas and related industries. To be clear, standard volumes are not the same as actual volumes since density depends upon pressure, temperature, and composition.

Below is a sample calculation illustrating the conversion of 150,000 metric tons/year of CO_2 into barrels per day (bpd) assuming 365.25 days per year, with the conversion factors and other constants sourced from the Gas Processors Suppliers Association (GPSA) Engineering Data Book (GPSA 2016):

$$\left(\frac{150{,}000\ metric\ ton}{1\ year}\right)\left(\frac{2204.62\ lb}{1\ metric\ ton}\right)\left(\frac{1\ lbmol}{44.0095\ lb}\right)\left(\frac{6.4598\ gal}{1\ lbmol}\right)\left(\frac{1\ bbl}{42\ gal}\right)\left(\frac{1\ year}{365.25\ day}\right)$$

$$= 3{,}164\ bpd$$

bpd = barrels per day
gal = gallon(s)
lb = pound(s)
lbmol = pound-mole(s)

Pressure (P) can be reported as either absolute pressure ($P_{absolute}$) or gauge pressure (P_{gauge}), where the relationship between the two is:

$$P_{absolute} = P_{gauge} + P_{atmospheric}$$

Pressure will generally be reported in this project using US customary units of psia for absolute pressure, psig for gauge pressure, and psi for differential pressure. The reference value for atmospheric pressure ($P_{atmospheric}$) used to interconvert between absolute and gauge scales varies depending upon context. Standard barometric pressure at sea level is 14.696 psia, which is the reference value used for some pressure gauges (e.g., strain gauges) and certain engineering calculations (e.g., internal calculations for commercial software packages). Other physical gauges (e.g., Bourdon tube gauges) utilize the actual atmospheric pressure at the gauge location, which can often be approximated as the standard barometric pressure adjusted to the surface elevation of CSS #1 per the barometric formula (Wikipedia 2023):

$$P_{atmospheric} \approx P_b \left[\frac{T_b + (h - h_b)L_b}{T_b}\right]^{\frac{-g_0 M}{R^* L_b}}$$

$$P_{atmospheric} \approx 14.696 \left[\frac{288.15 + (1810.7 - 0)(-0.0019812)}{288.15}\right]^{\frac{-(32.17405)(28.9644)}{(8.9494596\, x\, 10^4)(-0.0019812)}}$$

$$P_{atmospheric} \approx 13.8\, psia$$

using the following values for the constants (Wikipedia 2023):

P_b = reference pressure: 14.696 psia
T_b = reference temperature: 288.15 Kelvin (K)
L_b = temperature lapse rate: -0.0019812 K/ft
h = height: 1,810.7 ft (ground level for CSS #1 per stratigraphic well permit)
h_b = reference height: 0 ft
R^* = Universal gas constant: 8.9494596 x 10^4 lb ft^2/(lbmol K s^2)
g_0 = Standard acceleration of gravity: 32.17405 ft/s^2
M = Molar mass of Earth's air: 28.9644 lb/lbmol

The composition of the CO_2 stream will be continuously monitored using AN-0501 – a non-dispersive infrared (NDIR) instrument that is located just upstream of the injection flowmeter, proximate to the surface location of CSS #1 as discussed previously in Section E.5.1. In addition, CO_2 stream composition will be measured via laboratory analysis of grab samples taken from the quick connect for lab grab samples integrated in the sample station hardware for AN-0501, located just upstream of the injection flowmeter, proximate to the surface location of CSS #1. See Section E.I.1.4 of the QASP for additional details.

E.7. Corrosion Monitoring [40 CFR 146.90(c)]

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

PCC will monitor corrosion using the corrosion coupon method and collect samples according to the description herein.

E.7.1. Monitoring Location and Frequency

Corrosion coupons will be mounted into inline holders inserted into the full CO_2 stream. The holders will be installed in a straight section of pipe at the entrance to the pipeline between the last stage of compression and the launcher for pipeline inspection pigs. This location was selected since it is representative of the CO_2 conditions in contact with the injection well components, yet it is easily accessible to PCC staff and subcontractors and is within the security perimeter for the surface equipment. On a quarterly basis during the Injection period, each coupon will be exposed to the CO_2 injectate, removed for cleaning and analysis, and replaced with a new coupon of the same material for the next testing cycle. No coupon testing will occur during the Pre-Injection or PISC periods since the CO_2 stream will not be available.

Table E.7-1. Well Component Materials and Coupons Crosswalk

		Representative Coupons for Wetted Surfaces				
	Well Component	**Carbon Steel, API 5L X52 PSL2**	**Austenitic Stainless Steel, 304L SS - UNS S30403**	**Martensitic Stainless Steel, 13CR-L80 - UNS S42000**	**Superalloy Steel Alloy 925 - UNS N09925**	**Nickel-Plated Carbon Steel**
CSS #1	**Surface Facilities**					
	Wellhead	✓				
	Surface Piping	✓				
	Valves	✓				
	Instruments		✓			
	Subsurface					
	Casing - Long String			✓		
	Packer				✓	
	Tubing			✓		
	Instruments					✓

E.7.2. Sample Description

Table E.7-1 provides a crosswalk between the well component metallic surfaces expected to come in contact with CO_2 vs. corrosion coupons representing those wetted surfaces. The coupon types are identified by the type of steel, common name, and where appropriate the unified numbering system (UNS) identifier widely used in North America to designate alloy chemical composition or in some cases a specific mechanical or physical property. A UNS number alone does not provide a full material specification because it does not establish material properties, heat treatment, form, or physical property. The two left-most coupons listed in the heading of Table E.7-1 (i.e., Carbon Steel API 5L X52 PSL2 and Austenitic Stainless Steel 304L SS – UNS S30403) are commonly used materials in the upstream Surface Equipment and Pipeline units and surface facilities for the injection well and thus are included in the testing matrix. The right-most coupons listed in Table E.7-1 are representative of the wetted metallic surfaces of subsurface well components as indicated by the check marks. The coupons will be either commercially purchased corrosion coupons and/or coupons fabricated from excess materials used for construction and installation of the equipment.

E.7.3. Monitoring Details

Each new coupon will be prepared then installed into holders that place the coupon close to the center of flow for the full CO_2 stream, with flow passing the coupons any time injection is occurring except when the coupons are undergoing changeouts. No other processing equipment will act on the CO_2 stream past the placement of the coupon holders (other than piping, valving, and instruments); thus, the system will provide representative exposure of the coupons to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing.

PCC or its designated subcontractor will be responsible for initiating each monitoring event. Specifically, the PCC representative will:

- Coordinate preparation of new coupons for exposure to the CO_2 stream, following the method provided in Section E.I.2.2.a/b of the QASP.
- Coordinate collection and installation of coupons with Operations. Retrieve previously installed coupons from their holders, and install the newly prepared coupons for testing. No coupon previously exposed to the CO_2 stream is to be reused; only new prepared coupons will be installed per Section 2.1 of NACE International (NACE) SP-775-2018 (NACE 2018).
- Record all necessary identifying information during collection and installation of the coupons (e.g., field operator name & company affiliation, collection time and date, coupon location, coupon serial number)
- Visually inspect the retrieved coupons exposed to the CO_2 stream, and record written notes and photographs showing signs of erosion, pitting, scale, or other damage
- Place the retrieved coupons in protective packaging and ship them to the third-party analyst.
- Review and interpret test results, and report finding to US EPA.

See Section E.I.2.2 (and its subsections) of the QASP for additional detail on the corrosion coupon program.

Complementary methods to corrosion coupon monitoring are the well integrity methods described earlier: Section E.3 Internal Mechanical Integrity, and Section E.4 and External Mechanical Integrity. These testing and monitoring plan elements ensure well integrity.

E.8. Pressure Fall-Off Testing [40 CFR 146.90(f)]

PCC will perform pressure fall-off tests during the injection period as described below to meet the requirements of 40 CFR 146.90(f).

E.8.1. Testing Location and Frequency

A pressure fall-off test will be performed in the injection well CSS #1 at the following times:

- Prior to initiation of CO_2 injection
- At least once per every 5-year period during the Injection period
- At the end of the Injection period

E.8.2. Testing Details

Pressure fall-off tests are used to measure formation properties in the vicinity of the injection well. The objective of periodic testing is to monitor for any changes in the near-well bore environment that may impact injectivity and other well/reservoir performance metrics.

Pressure fall-off tests are conducted by ceasing injection for a period of time (i.e., shutting-in the well) and monitoring wellhead and bottomhole pressures and temperatures. The results of the pressure fall-off test depend in part on the injection conditions prior to shutting-in the well. Therefore, prior to the test, the injection rate and pressure will be kept as constant as practical and will be recorded by the instruments described previously in Section E.6 Monitoring of Operational Parameters.

The duration of the shut in period will follow the US EPA guideline of three to five times the time required to reach infinite-acting radial flow (IARF) conditions (EPA 2013). This duration is well beyond the time period when wellbore storage effects can impact the data. Establishment of IARF conditions is indicated by a straight line on a standard semi-log plot of pressure response vs. log of the fall-off/recovery time.

Test results will be analyzed as follows:

- Linear-linear plots (aka Cartesian plots) of bottom-hole pressure versus time and bottom-hole temperature versus time for the period prior to shut-in and the duration of the test will be used to confirm stabilization prior to commencement of the test.

- Log-log plots of the pressure versus the time function and/or the semi-log derivative of pressure versus the time function will be used to identify flow regimes present in the well test. The appropriate time function used in these plots will be determined using the procedure discussed in Section 7.0 and the Appendix of the US EPA Region 6 Pressure Falloff Testing Guideline (EPA 2002a) and related US EPA documents (EPA 2002b, EPA 2003).
- Semi-log plot of pressure versus the log of the time function will be used to compute reservoir transmissibility, skin factor, radius of investigation, effective wellbore radius, reservoir injection pressure corrected, and other parameters as discussed in Section 7.0 and the Appendix of the US EPA Region 6 Pressure Falloff Testing Guideline (EPA 2002a) and related US EPA documents (EPA 2002b, EPA 2003). Any computer software used for curve matching of the data will be identified in the test report.

Common sense checks for anomalous data responses will be evaluated and explained as discussed in the Appendix of the US EPA Region 6 Pressure Falloff Testing Guideline (EPA 2002a) and related US EPA documents (EPA 2002b, EPA 2003). These checks include examinations for multiple fluid phases, gravity driven flow, and dissolution of CO_2 in brine.

The instruments used for the pressure fall-off test will be the same as those described previously in Section E.6 Monitoring of Operational Parameters.

E.9. Groundwater Quality and Geochemical Monitoring [40 CFR 146.90(d)]

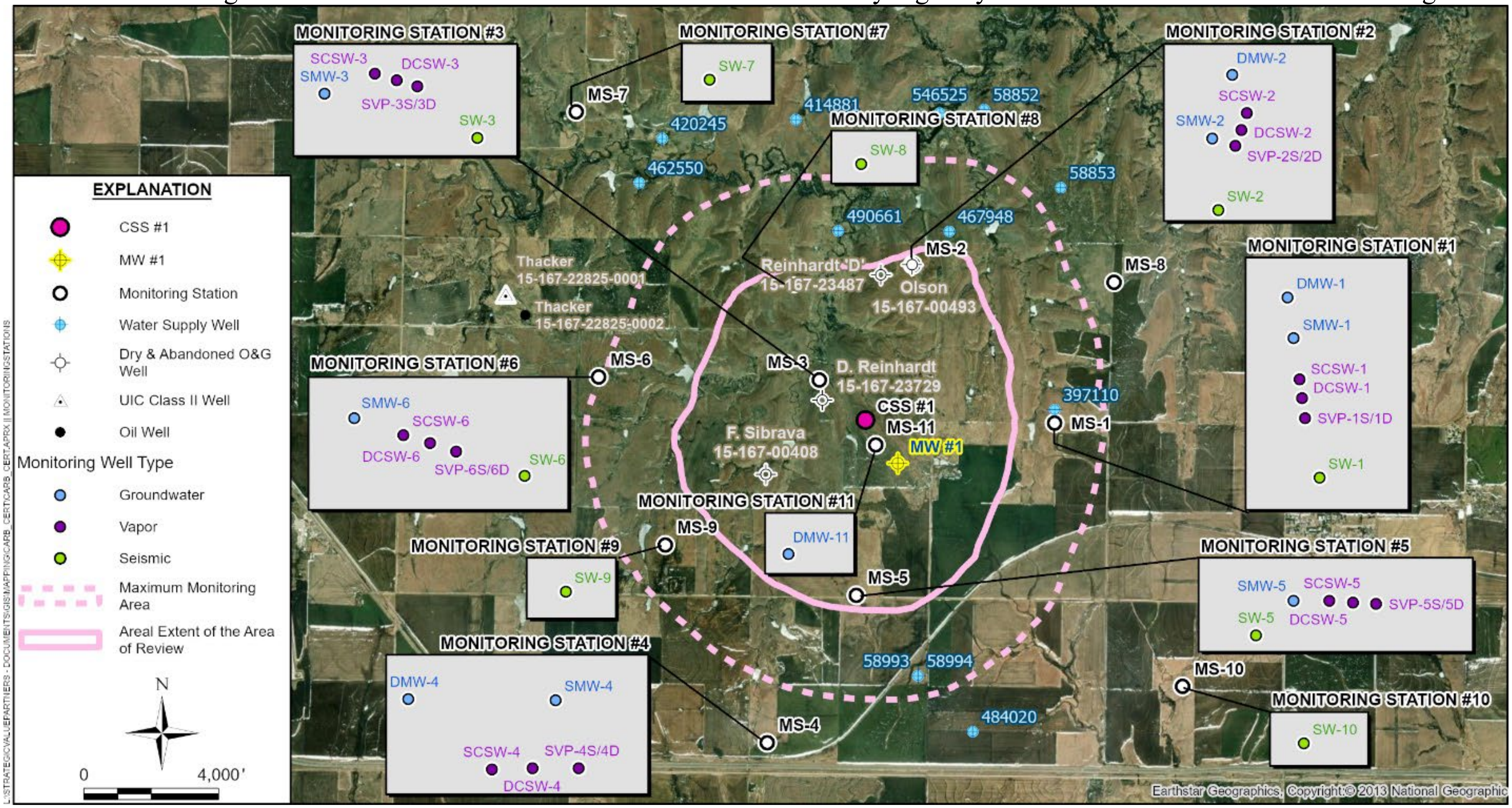
PCC will monitor groundwater quality for potential geochemical changes above the upper primary confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

E.9.1. Monitoring Locations and Frequency

PCC has installed a network of seven stations (MS-1 through MS-6, MS-11) for monitoring groundwater in the water table and the lowermost USDW within and in the vicinity of the AoR and MMA as illustrated in Figure E.9-1. Monitoring stations MS-1, MS-2, and MS-4 through MS-6 contain a shallow monitoring well (SMW-1, SMW-2, and SMW-4 through SMW-6) for monitoring groundwater within the surficial groundwater zone (water table). Due to its location and lower elevation on the side slope of a ridge, the shallow monitoring well at MS-3, SMW-3, actually monitors the Dakota formation along with the 4 deep monitoring wells (DMW-1, DMW-2, DMW-4, and DMW-11). See Attachment A.II Well Construction Details for depth and other details for each above confining zone monitoring well.

Figure E.9-1. Above Upper Confining Zone Monitoring Well Locations

Note: Monitoring Station #4 does not house a seismometer since the nearby highway would induce excessive noise in the signal



Groundwater quality at MS-1 through MS-6 will be continuously monitored for water level (pressure), temperature, conductivity, and salinity using downhole multi-parameter data loggers installed in each above confining zone monitoring well. Groundwater quality data are transmitted to PCC (and its subcontractors) by telemetry for real-time remote monitoring. Data loggers are also installed at each monitoring station for redundancy in case of a failure in the telemetry system.

Geochemical monitoring and selected isotope analysis of groundwater above the upper primary confining zone will be accomplished by laboratory analysis of grab samples from each of the shallow and deep monitoring wells in MS-1 through MS-6 and MS-11. In addition, PCC will also monitor groundwater in the first aquifer above the primary upper confining zone (i.e., the Iola Limestone member in the Kansas City Group) via geochemical laboratory analyses of samples periodically taken from MW #1 (upper zone).

Table E.9-1 summarizes the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the upper primary confining zone.

Table E.9-1. Summary of Above Upper Confining Zone Groundwater Quality and Geochemical Monitoring

Target Formations	Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Greenhorn Limestone (Water Table), Dakota Fm (Great Plains Aquifer) [Lowermost USDW]	Groundwater Quality	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3 SMW-4, DMW-4 SMW-5 SMW-6	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Continuous
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Data Logger Only
Greenhorn Limestone (Water Table), Dakota Fm (Great Plains Aquifer) [Lowermost USDW]	Geochemical Monitoring	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3 SMW-4, DMW-4 SMW-5 SMW-6 DMW-11	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Annual
				Injection	Annual
				PISC	Initial: Annual Maintenance: Every 5 years
Iola Limestone Member of Kansas City Group (First Aquifer Above Primary Upper Confining Zone)	Geochemical Monitoring	MW #1 (upper zone)	Single point measurements	Pre-Injection	Annual
				Injection	Year 1-3: Annual Year 4+: Quarterly until plume passes After Plume Passes: Annual
				PISC	Initial: Annual Maintenance: Every 5 years

The locations of monitoring stations MS-1 through MS-6 and MS-11 were selected to provide broad coverage across the areal extent of the AoR and the MMA, while the main technical siting criterion for MW #1 was a location within the areal extent of the AoR near the perimeter of the Year 5 plume. Table E.9-2 computes the above primary confining zone monitoring well density defined as the number of above confining layer groundwater wells per surface area of the areal extent of the AoR, the MMA, and for the overall project. The US EPA used the assumption of one above upper primary confining zone monitoring well per two square miles of AoR for the purpose of estimating national costs for the Class VI program (EPA 2010), equivalent to an above confining zone monitoring well density of 0.5 wells/mi^2 for the areal extent of the AoR. The calculations in Table E.9-2 show the well density for the GS project exceeds the well density used by US EPA in its rule making, suggesting the project has an adequate number of above primary confining zone groundwater monitoring wells.

Table E.9-2. Above Confining Zone Monitoring Well Density

Region	Number of Monitoring Wells	Well Identifiers	Surface Area (approximate mi^2)	Monitoring Well Density (wells per mi^2)
Areal Extent of AoR	3	SMW-3, DMW-11 MW #1 (upper zone)	1.4	2.1
Areal Extent of AoR + MMA	9	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3 SMW-5, DMW-5, DMW-11 MW #1 (upper zone)	4.5	2.0
Overall Project	11	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3 SMW-4, DMW-4 SMW-5, SMW-6 DMW-11 MW #1 (upper zone)	9	1.2

mi^2 = square mile(s)

PCC has installed one monitoring well MW #1(lower zone) within the AoR for pressure monitoring and fluid sampling of the injection zone formation. The density of injection zone monitoring wells is 1/1.4 = 0.7 wells per mi^2 of the areal extent of the AoR, which compares favorably to the US EPA assumption of 0.25 wells per mi^2 used in estimating national costs for the Class VI program (EPA 2010), suggesting the GS project has an adequate number of injection zone monitoring wells.

The locations of monitoring stations MS-1 through MS-6 and MS-11 were selected to meet specific characteristics of the site. As shown in Figure E.9-1, many stations provide measurements near/in the vicinity of the project wells CSS #1 and MW #1 (e.g., MS-11) and existing water wells and legacy oil and gas wellbores (e.g., MS-1 is near water well 397110, MS-2 is near legacy wellbore Olson 15-167-00493 and in the vicinity of Reinhardt ‘D’ 15-167-23487, MS-3 is near legacy wellbore D. Reinhardt 15-167-23729, and MS-6 is near legacy wellbore 15-167-23441) as these are locations with higher risks for CO_2 leakage to the surface. Furthermore, MS-4 is located comparatively far outside the MMA in order to provide on-going background groundwater measurements. MS-4 is located to the south of the MMA, and thus it is upstream of the MMA given the predominately north to northeast flow of surface and above confining zone groundwater for the project area. Groundwater elevations measured at MS-4 are approximately 15-20 feet higher than northern monitoring stations for the project, confirming groundwater flow to the north-northeast. On-going background measurements from MS-4 should assist in interpreting whether anomalous results from the other monitoring stations are indicative of non-containment of CO_2 from the GS project, or indicative of a larger regional disturbance in groundwater from some other root cause.

E.9.2. Analytical Parameters

Table E.9-3 identifies the parameters to be monitored and the analytical methods PCC will use.

Internal consistency of the geochemical results for each sample will be validated using the charge balance and material balance per the procedures given in Section E.I.2.5.c of the QASP. Outlier data will be identified using the procedures given in Section E.I.2.5.c of the QASP. Statistical time-series analysis will be used to establish baseline values for groundwater quality and geochemical analysis using a minimum of four quarterly samples taken during Pre-Injection. Material deviations of data taken during Injection and/or PISC from above confining zone stations vs. baseline values may potentially indicate non-containment, although a thorough analysis of alternative causes for such anomalous data should be carried out before declaring a non-containment event. See Section H.4.3 of the Emergency Remedial and Response plan for actions to be taken in the event of a Potential Brine or CO_2 Leakage to USDW or the Surface.

Baseline sampling of groundwater at the MS-1 to MS-6 stations taken during the Pre-Construction period (see Site Characterization document) indicates groundwater of variable geochemical composition, possibly related to formation type for a given well screen (e.g., carbonate vs. shale or sandstone) and degree of hydraulic connection to vertically adjacent stratigraphic layers. The analyte list is sufficient to characterize the dominant cations and anions for a given well, and whether at baseline these water types vary seasonally. Over the lifetime of the project, and in particular during Injection and PISC, the analytes are sufficient to determine whether the geochemical signature at a given well deviates from baseline (e.g., transition out of a specific dominant cation or anion regime). Any potential deviations from baseline for a given parameter would be considered in the context of other lines of evidence (e.g., shift in carbon isotopes) before triggering an evaluation of potential additional parameters to incorporate to that monitoring list.

E.9.3. Sampling Methods

Sampling methods for samples taken from MS-1 through MS-6 and MW #1 are described in Section E.I.2.2 of the QASP.

E.9.4. Laboratory to be Used/Chain of Custody Procedures

Sample handling and custody are described in Section E.I.2.3 of the QASP. Laboratory analytical methods are described in Section E.I.2.4 and Appendix C of the QASP. Field quality control is described in Section E.I.2.5 of the QASP.

Table E.9-3. Summary of Analytical and Field Parameters for Groundwater Samples

Locations/Target Formations	Analytes	Analytical Methods[1,2]
MS-1 through MS-6/ Greenhorn Limestone (Water Table) Dakota Formation (Great Plains Aquifer) [Lowermost USDW]	Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
	Cations: Ca, Fe, Mg, Na, Potassium, and Si	ICP EPA Method 6010B
	Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
	Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry[3]
	Total dissolved solids	SM 2540C
	Alkalinity, Total (as $CaCO_3$)	SM 2320B
	Alkalinity, Carbonate (as $CaCO_3$)	SM 2320B
	pH (field)	Field Meter
	Dissolved CO_2 (field)	Field Meter
	Dissolved Oxygen (field)	Field Meter
	Turbidity (field)	Field Meter
	Specific conductance (field)	Field Meter
	Temperature (field)	Field Meter
	Depth to water (field)	Field Meter
	Water pressure/depth, temperature, and conductivity/salinity (field)	See Continuous Monitoring of Groundwater Quality
MW #1 (upper zone)/ Iola Limestone Member of Kansas City Group (First Aquifer Above Primary Upper Confining Zone)	Same analytes and analytical methods as those for MS-1 through MS-6 samples. Pressure and temperature readings recorded from downhole instruments installed in MW #1 (upper zone).	

Note 1: An equivalent method may be employed with prior approval of the US EPA UIC Program Director

Note 2: All chemical analyses will be performed by a certified laboratory under the Environmental Laboratory Approval Program protocols; field measurements will be recorded by a qualified professional

Note 3: Gas evaluation technique by Atekwana and Krishnamurthy 1998, with modifications made by Hackley et al. 2007

Al = Aluminum
As = Arsenic
Ba = Barium
Br = Bromide
Ca = Calcium
$CaCO_3$ = Calcium carbonate
Cd = Cadmium
Cl = Chloride
Cr = Chromium
Cu = Copper
Fe = Iron
ICP = Inductively coupled plasma
ICP-MS = Inductively coupled plasma mass spectrometry
Mg = Magnesium
Mn = Manganese
Sb = Antimony
Se = Selenium
Si = Silicon
SM = Standard Method
SO_4 = Sulfate
Tl = Thallium

E.10. Plume Tracking [40 CFR 146.90(g)]

The plume and pressure front monitoring methods are designed as a complementary suite of methods, with results from one method providing a means to confirm results from another, thus creating a certain amount of redundancy in the event of failure for any one method in the suite. PCC will employ a combination of direct and indirect geophysical methods to track the extent of the carbon dioxide plume to meet the requirements of 40 CFR 146.90(g). The direct method consists of periodic grab sampling from the bottom zone of MW #1 with laboratory geochemical and isotope analyses of the injection zone fluid sample. The indirect geophysical method utilizes time-lapse two-dimensional (2D) and/or three-dimensional (3D) surface seismic surveys across the MMA and vicinity. Section E.11 describes the complementary pressure front monitoring methods.

E.10.1. Plume Monitoring Location and Frequency

Table E.10-1 summarizes the methods that PCC will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies PCC will employ.

Table E.10-1. Plume Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location	Spatial Coverage	Period	Frequency
DIRECT PLUME MONITORING					
Arbuckle	Laboratory geochemical and isotope analysis of formation fluid grab samples	MW #1 (lower zone)	Single Point Location	Pre-Injection	Annual
				Injection	Year 1-3: Annual Year 4+: Quarterly until plume passes, then cease monitoring
				PISC	Not Applicable
INDIRECT PLUME MONITORING					
Arbuckle	Time-lapse 2D/3D surface seismic surveys	MMA and Vicinity	MMA and Vicinity	Pre-Injection	One 3D survey (baseline)
				Injection	2D/3D survey every 5 years, plus one 3D survey at end of Injection period
				PISC	2D/3D survey every 5 years from start of PISC, plus one 3D survey at end of period

E.10.1.1. Direct Plume Monitoring

The main objective of the direct plume monitoring program is to experimentally confirm the time of passage for the CO_2 plume at MW #1. The direct plume monitoring method utilizes grab sampling and laboratory analyses of injection zone fluid samples collected from the lower zone of MW #1, with MW #1 located roughly on the anticipated perimeter of the CO_2 plume at Year 5 of the Injection period.

The planned sampling frequency for direct plume monitoring changes over time in order to catch the passage of the plume. A baseline Pre-Injection sample will be taken followed by annual sampling through the end of Year 3 of the Injection period since the plume is not anticipated to arrive during these times. Sampling frequency is increased to quarterly starting in Year 4 to ensure catching passage of the plume. The computational model predicts the CO_2 plume will arrive at MW #1 as a wave (see Section B.3 of the Area of Review and Corrective Action Plan), with the formation fluid CO_2 gas saturations rising quickly from 0% to ~35% as the front passes.

Quarterly sampling for direct plume monitoring will continue until the data indicate the plume has reached and started to pass MW #1 as indicated by positive results for the presence of CO_2 from at least two consecutive quarterly tests [or an alternate criterion approved by the US EPA Underground Injection Control (UIC) Director], at which point PCC will seek approval from the US EPA UIC Program Director to cease direct plume monitoring activities since the main objective of the direct plume monitoring program will be complete. A positive result for the presence of CO_2 is defined as a drop in the field pH measurement of 1.0 units (or more) vs. baseline field pH for injection zone fluid. The US EPA UIC Program Director decision to approve cessation of direct plume monitoring activities will be informed by data PCC provides on direct plume monitoring plus additional data from the complementary suite of plume and pressure front monitoring methods and the computation model.

E.10.1.2. Indirect Plume Monitoring

The main objective of the indirect plume monitoring program is to experimentally confirm the underground location of the CO_2 plume over the Injection and PISC periods using a series of time-lapse surface seismic surveys across the MMA and vicinity. These data will in turn be used to support AoR re-evaluations and updates to the computational model as required in 40 CFR 146.84(b)(2) and 40 CFR 146.84(c). The current schedule of AoR re-evaluations once every five years is reflected in the frequency of seismic surveys listed in Table E.10-1.

E.10.2. Plume Monitoring Details

E.10.2.1. Direct Plume Monitoring

The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table E.10-2. The parameter list for injection zone formation fluid samples differs slightly from the parameters presented earlier in Section E.9.2 for groundwater samples because the injection zone samples are expected to have a slightly different sample matrix as the CO_2 and formation fluids sweep through the injection zone.

See Sections E.I.2.2, E.I.2.3, E.I.2.4 of the QASP for more details on sampling procedure, sample handling and custody, and laboratory analytical methods, respectively.

Table E.10-2. Summary of Analytical and Field Parameters for Fluid Sampling in the Injection Zone

Target Formation	Analytes	Analytical Methods[1,2]
Arbuckle (Injection Zone)	Cations: Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Ni, potassium, Se, SiO_2, Si, Ag, Na, Sr, V, Zn	ICP EPA Method 6010
	Anions: Br, Cl, F, NO_3, nitrite, and SO_4	Ion Chromatography EPA Method 300.0
	Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry[3]
	Ammonia, as N	EPA 350.1
	Sodium Adsorption Ratio (SAR)	EPA 6010
	Mercury	EPA 7470
	Phenol	EPA 8270
	Oil and grease	EPA 1664A
	Ferric and ferrous iron	SM 3500
	Total dissolved solids	SM 2540C
	Alkalinity, Total (as $CaCO_3$)	SM 2320B
	pH	SM 4500
	Total sulfide and sulfide as H_2S	SM 4500
	Total CO_2	SM 4500
	Cyanide	SM 4500
	Total organic carbon	SM 5310C

Note 1: An equivalent method may be employed with prior approval of the US EPA UIC Program Director

Note 2: All chemical analyses will be performed by a certified laboratory under the Environmental Laboratory Accreditation Program (ELAP) protocols; field measurements will be recorded by a qualified professional

Note 3: Gas evaluation technique by Atekwana and Krishnamurthy 1998, with modifications made by Hackley et al. 2007

Ag = Silver
B = Boron
Be = Beryllium
Co = Cobalt
F = Fluoride
Li = Lithium

N = Nitrogen
Na = Sodium
Ni = Nickel
NO_3 = Nitrate
Pb = Lead

SiO_2 = Silicon dioxide
Sr = Strontium
V = Vanadium
Zn = Zinc

E.10.2.2. Indirect Plume Monitoring

PCC conducted a baseline 3D surface seismic survey in 2022 to characterize subsurface rock formations (e.g., depth, areal extent, thickness) in accordance with 40 CFR 146.82(a)(3)(iii). Time-lapse surface seismic surveys using the 2022 baseline survey as a reference will be used as an indirect geophysical method to track the CO_2 plume over the life of the GS project. This subsection documents the 2022 baseline seismic shoot and data processing to allow for accurate reproduction of survey conditions during follow-on acquisitions.

Paragon Geophysical Services, Inc. conducted the baseline field survey during August through September 2022. The baseline survey fully encompassed the areal extent of the AoR as shown previously in Figure E.2-2. Figure E.10-1 is a map providing detailed locations for the receivers and sources utilized in the baseline survey. The exact GPS coordinates for the receiver and source locations are recorded in the Time and Depth Process of Field Data file attachment. The grid layout provides sufficient coverage in the general vicinity around CSS #1, even though the location for CSS #1 was not finalized at the time of the baseline survey. Figure E.10-2 summarizes the equipment and methods used to collect the field data. Additional information is available in the Paragon report attachment.

DataSeismic Geophysical Services (DataSeismic) conducted time and depth processing of the field data collected previously by Paragon Geophysical Services, Inc. and consolidated the information into a set of files collectively called the Russell East 3D volume. The primary goal of the time processing was to produce high quality amplitude compliant gathers ready for input to pre-stack time migration, depth imaging, and inversion, with specific objectives to have good resolution in the shallow data and good definition of the Arbuckle Group and Basement. Table E.10-3 provides a summary of the final time processing sequence. The depth processing utilized a sequence of Z-Terra's 3-D Kirchoff depth migration algorithm; tomographic updates of the velocity model; post processing filtering; and Gaussian Beam Migration plus Reverse Time Migration. Additional information is available in the DataSeismic report attachment.

Figure E.10-1. Layout of Receivers and Sources for Baseline 3D Surface Seismic Survey

Blue Circles = Receivers in East-West Orientation; Red Triangles = Sources in Southwest-Northeast Orientation

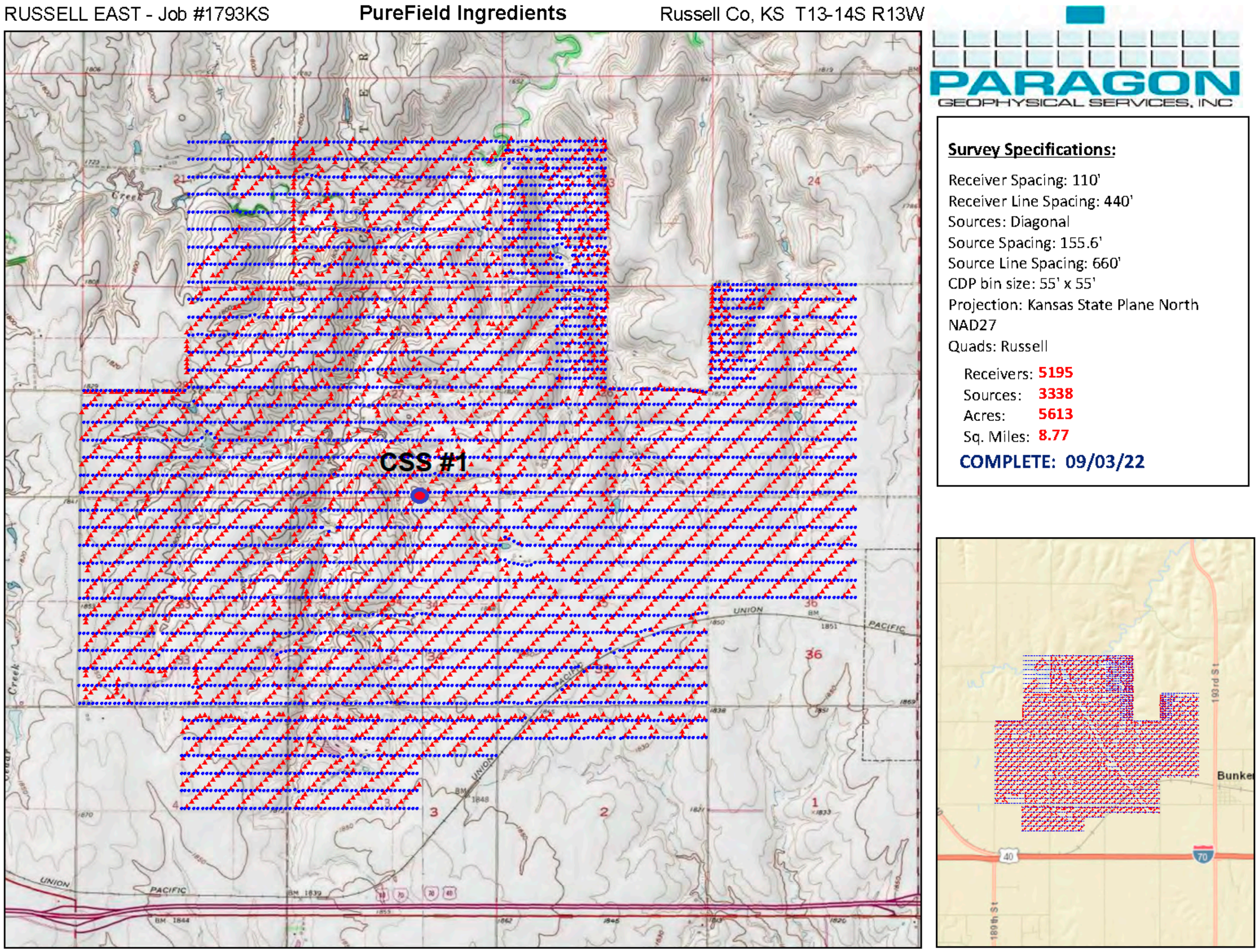


Figure E.10-2. Summary of Equipment and Methods Used for Baseline 3D Surface Seismic Survey

PARAGON GEOPHYSICAL SERVICES, INC

Job # 1793
Russell East
PureField Ingredients
Russell/KS

Client Representative: Jim Imbler

Crew #220
08/23/22

Crew Contacts

Paragon Geophysical Services	
Supervisor	Erick Erwin 316-305-8494
Crew Manger	Adrian Sanchez-(970)-739-7350
Transcriber	Chad Hall/Jeremy McIntosh-(251)-227-5163
Senior Observer	Armando Rios (620)- 391-5713
Survey Manager	Shawn Bond(719)529-0436
Survey	
Permit Agent	Cougar - Art Luna
Mechanic	David Gonzale (785)-259-2473

Recording System

Recording System	E-428 / Sercel Wing
Software Version	Version 6.6 patch 7 / Version 3 patch 7.0
System Output	Seg-D Version 2.1

		Vibrator		Dynamite
Auxiliary CH 1	1	Pilot		1
Auxiliary CH 2	2	True Ref		2
Auxiliary CH 3	3	Ground Force		3

Digital Field Unit (DFU)

Sensor Type	MEMS Accelerometer
Frequency	0 to 400Hz
Pattern	Single

Recording Parameters

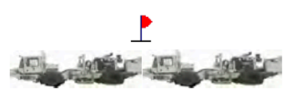
Sample Rate	1	ms
Low Cut filter	0.15625Hz	Hz
High Cut Filter	400	Hz .8 Nyquist minimum
Preamp Gain	0	dB (G-1)
Noise Editing	Diversity Stack	
Data to Hard Drive	Raw / Correlate after Stack	
Record Length	2	sec
Line Type	3D	
Active lines	24	
Active Channels per line	96	
Full Spread	1728	
Roll On / Off	Roll On/Off	
Receiver Per square mile	445.00	
Receiver Line Interval	440	
Receiver Group Interval	110	
Total Receiver Lines	36	
Total Receiver Groups	4647	Pre Plot
Receiver Orientation	E-W	
VP's Per square mile	301.00	
Source Line interval	660	
Source Point Interval	110	Effective
Total Source Lines	27	
Total Source Points	3146	Pre Plot
Source Orientation	SW-NE	
Total Sq. Miles	8	Preplot

Source Parameters

Energy Source	Vibrators
Vibrator Parameters	
Vibrator Model	I/O AHV IV
Source Control	Sercel VE-464
Hold Down Weight	62,000 lbs.
Drive Level	70 / 35 %
Phase Lock	Ground Force
Force Control	Fundamental Ground Force
Number Of Vibes	2 Vibrators Inline
Pattern	Centered on stake

Sweep Parameters

Number Of Sweeps	4	Linear
Move Up	Stacked	
Start Frequency	4	Hz
End Frequency	128	Hz
Sweep Length	12	Seconds
Sweep Type	+3dB	
Start Taper	500	ms
End Taper	200	ms



Processor

Data Seismic Geophysical Services
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Field Representative:
Jim Imbler
303-521-6240
jimbler@newphaseenergy.com

Signiture_________________________

Table E.10-3. Final Time Processing Sequence

Input Data (SEG-D)
Geometry generation and QC
Minimum Phase Conversion
Shot Domain Noise Attenuation
True Amplitude Recovery (TAR):
Time power constant: 2
Length: 2,000 ms
Surface Consistent Amplitude Compensation (SCAR); SR Contribution
Surface Consistent Deconvolution:
Type: Spiking
Operator Length: 160 ms
Components: Source, Receiver, Offset and CDP (SROC)
Air Blast Attenuation
Surface Consistent Amplitude Compensation (SCAR); SROC Contribution
Refraction Statics Corrections Application
First Velocity Analysis (1 every sq. mi.)
Normal Moveout Application
Surface Consistent Residual Statics Corrections
Second Velocity Analysis (4 every sq. mi.)
CDP Domain Noise Attenuation
Pre-stack Multidimensional Regularization and Interpolation
Normal Moveout Application
3D Kickoff Pre-stack Time Migration (First Iteration)
Residual Velocity Analysis (4 every sq. mi.)
Final 3D Kickoff Pre-stack Time Migration
Common Reflection Point gathers generation
Residual Moveout Correction
Stack and Shift to Final Datum (D = 1,900 ft; VR = 8,000 ft/s)
Time-Variant Bandpass Filter
Dip Guided Structural Filtering

Notes:

CDP = common depth point

ft = feet

ft/s = feet per second

ms = millisecond

sq. mi. = square mile

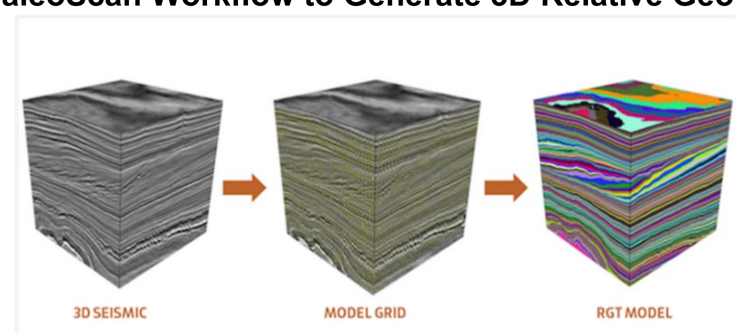
QC = quality control

The processed seismic data were interpreted using PaleoScan™1 (Version 2022.2, Release r39021) semi-automatic workflow for 3D seismic volumes. This workflow creates a 3D Relative Geological Time (RGT) model that lets the interpreter utilize RGT-based attributes on the flight (see Figure E.10-3). The workflow consists of the following steps:

- Model Grid Generation Paleoscan generates a 3D grid across the entire seismic volume on each polarity and connects data with similar characteristics to create a grid of horizon patches (see Figures E.10-4 and E.10-5). Using geological data, the size of the patches are manually adjusted according to the scale of the area of interest and local complexity.
- Auto Tracking Horizon Patched Edition On the second step of interpretation, horizon patches were linked automatically. This result was edited interactively and iteratively, connecting auto-tracked horizons and updating the model grid in real time.
- Relative Geological Time Model The RGT model is generated based on the previous two steps of interpretation (Figure E.10-6). The RGT model is also interpreted and edited to generate an interpretation adjusted to the geological and stratigraphic characteristics. The stratigraphic defined from the CSS #1 well was used as a constraint to adjust the model.
- Horizon Stack A Horizon Stack is generated based on the RGT model (Figure E.10-7). One hundred horizons were interpreted from 100 feet below surface level (BSL) to 2,000 feet BSL.
- Multi-Attribute Analysis A multi-attribute analysis using the Horizon Stack was implemented to interpret and characterize the stratigraphic units. DIP and Maximum Curvature attributes were used to observe the structural characteristics across the Russel East volume and identify karst structures and platform/reef morphology. Root Mean Square (RMS) was used to preliminary understand the distribution of similar rock properties based on their amplitude and energy. Other attributes such as Thinning and Spectral Decomposition, will provide a more detailed stratigraphic analysis and mapping of the Arbuckle Group.

Finally, stratigraphic units were defined based on the information provided by the CSS #1 well.

Figure E.10-3. PaleoScan Workflow to Generate 3D Relative Geologic Time Model



1 PaleoScan is a trademark of Eliis Inc.

Figure E.10-4. Model Grid of the Russell East 3D Volume

CSS #1 Well shows the GR profile. Green horizons represent top and bottom of Arbuckle Group

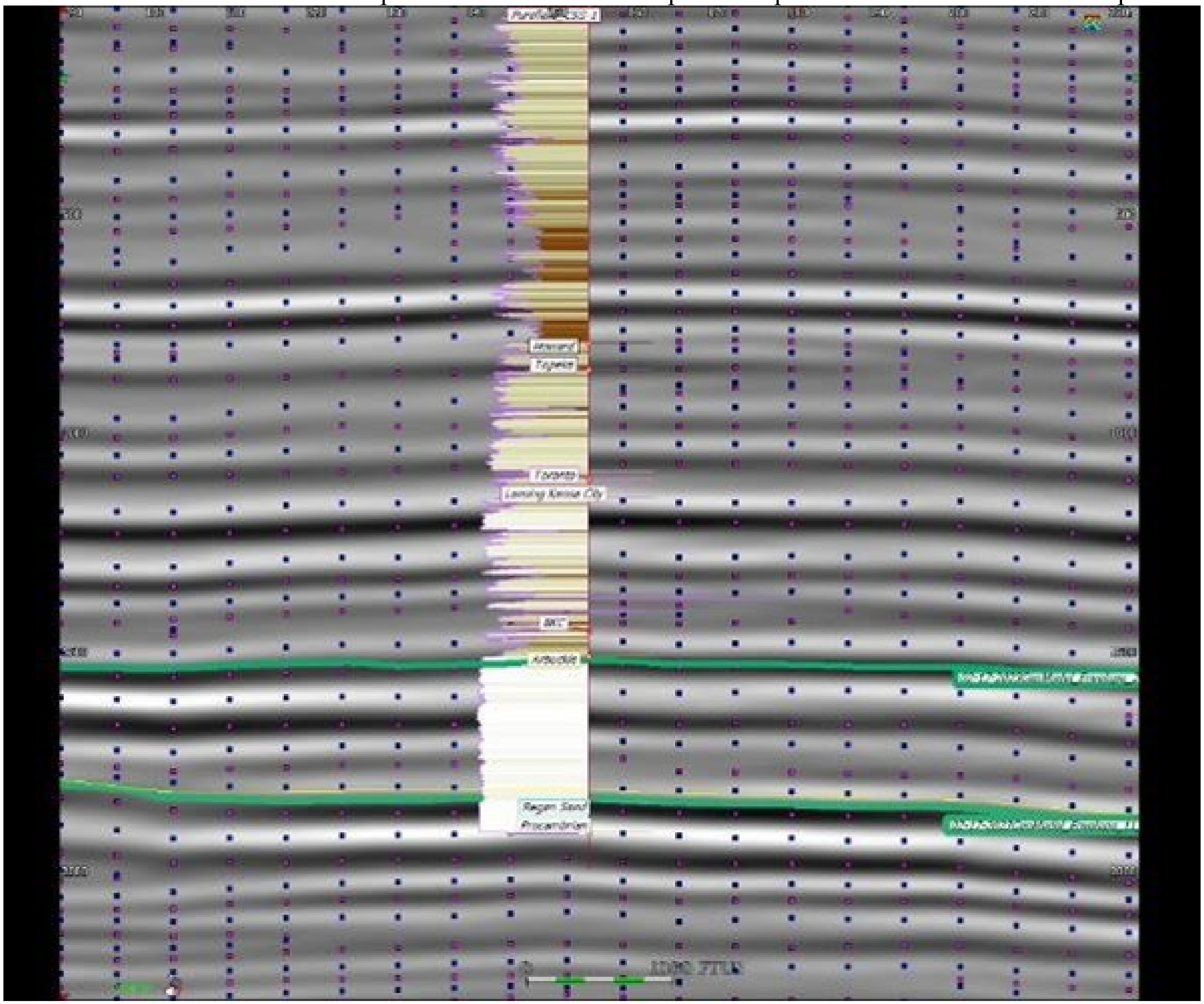


Figure E.10-5. Model Grid with Horizon Patched and Final Horizon Results
Yellow horizons are two examples of the 100 horizons interpreted.

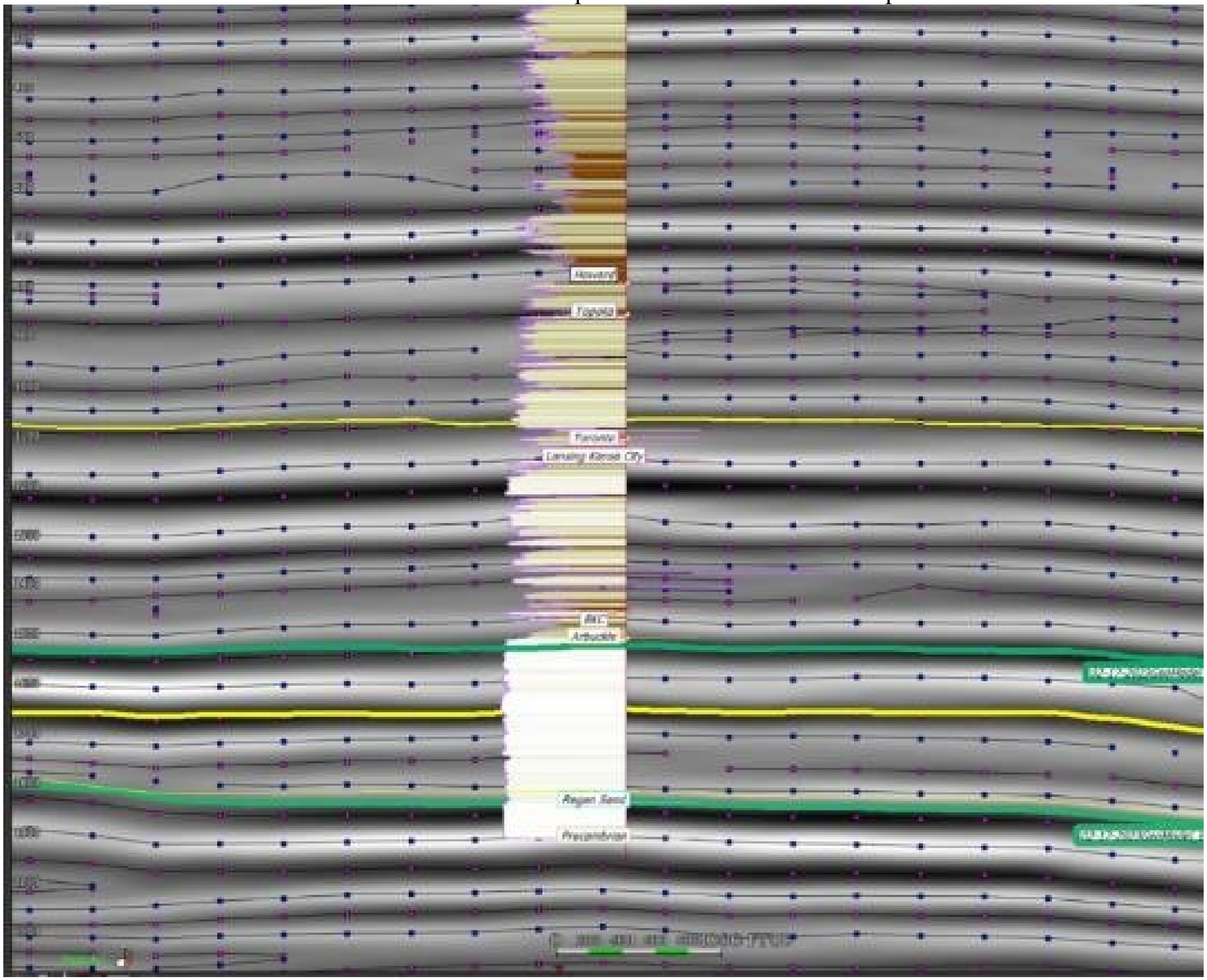


Figure E.10-6. 3D Relative Geologic Time Model of the Russell East 3D Volume

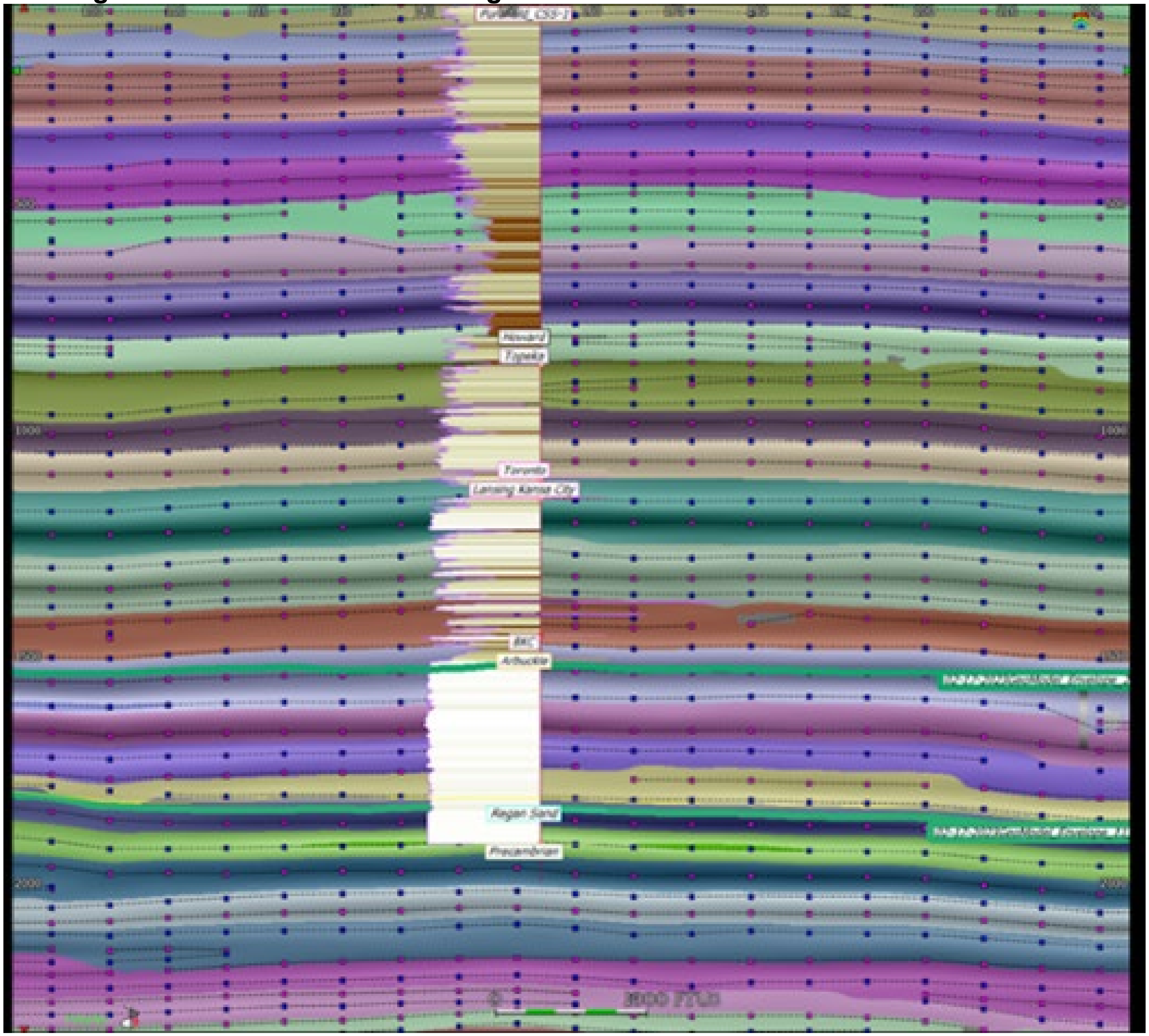
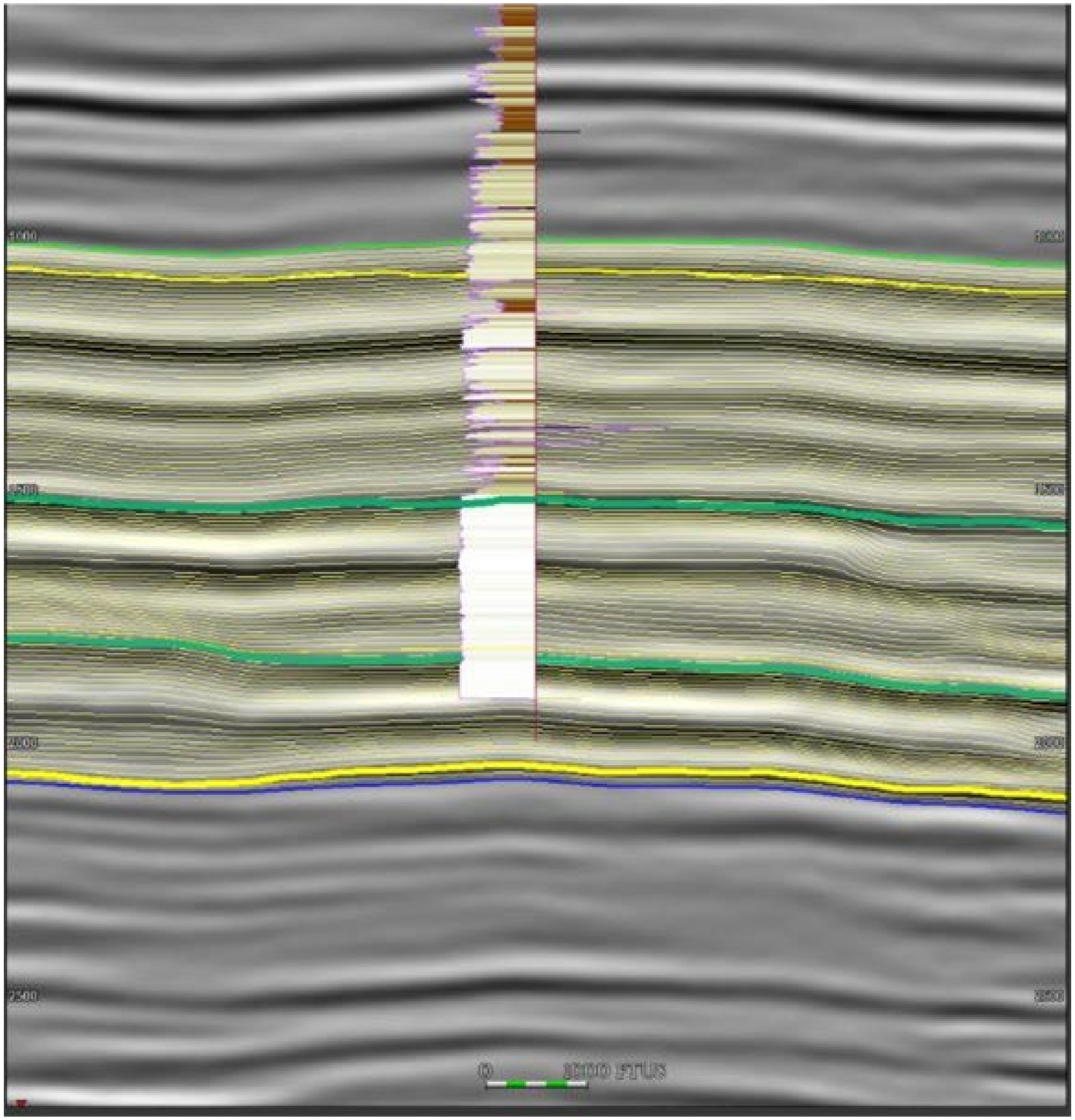


Figure E.10-7. Horizon Stack on Russell East 3D Volume

Yellow horizon are the one hundred horizons interpreted.



E.11. Pressure Front Tracking [40 CFR 146.90(g)]

The plume and pressure front monitoring methods are designed as a complementary suite of methods, with results from one method providing a means to confirm results from another, thus creating a certain amount of redundancy in the event of failure for any one method in the suite. PCC will employ a combination of direct and indirect geophysical methods to track the extent of the pressure front to meet the requirements of 40 CFR 146.90(g). The direct methods monitor downhole pressure gauges installed in CSS #1 and MW #1. The indirect geophysical method utilizes a dedicated passive seismic array to track micro-seismic events across the MMA and vicinity. The dedicated passive seismic array will also provide data to the seismic monitoring plan, as discussed in Section E.15.

E.11.1. Pressure Front Monitoring Location and Frequency

Table E.11-1 summarizes the methods that PCC will use to monitor the position of the pressure front, including the activities, locations, and frequencies PCC will employ.

Table E.11-1. Pressure Front Monitoring Activities

Target Formation	Monitoring Activity	Location	Spatial Coverage	Period	Frequency
DIRECT PRESSURE FRONT MONITORING					
Arbuckle	Monitor downhole pressure gauge	CSS #1	Single Point Location	Pre-Injection	Continuous (upon installation)
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Data Logger Only
	Monitor downhole pressure gauge	MW #1 (lower zone)	Single Point Location	Pre-Injection	Continuous (upon installation)
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Data Logger Only
INDIRECT PRESSURE FRONT MONITORING					
Arbuckle	Passive seismic tracking of micro-seismic events	MMA and vicinity	MMA and vicinity	Pre-Injection	Continuous
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Regional network only

E.11.2. Pressure Front Monitoring Details

E.11.2.1. Direct Pressure Front Monitoring

Downhole pressure gauges are installed in CSS #1 and MW #1 to measure the reservoir pressure over time at the specified gauge locations. These instruments produce essentially continuous readings of reservoir pressures, which are recorded at same frequency specified in Section E.6.1 for recording of Continuous Monitoring of Operating Parameters, with a local data logging back-up to improve resiliency of the data collection and recording system. The resulting recorded data are plotted over time to indicate the advancement/retreat of the pressure front at the two locations during the Injection and PISC periods. The resulting data are also used to update the computational model via history matching between the field data and the computational model results.

See Section E.I.1.4 of the QASP for more detail.

E.11.2.2. Indirect Pressure Front Monitoring

US EPA recognizes the use of passive seismic methods to track micro-seismic events across the AoR and MMA as a means for pressure front monitoring – see Section 5.3.1 of EPA 2013. This approach utilizes an array of extremely sensitive seismometers to detect extremely small subsurface acoustic events across the AoR and MMA, with typical event magnitudes of -1 M_w or lower - corresponding to event intensities that are $10{,}000^+$ times smaller than the smallest event that can be felt by a human.

Acoustic energy is emitted whenever there is slip on a fault or fracture development. This GS project is designed to limit pressure at the top of the injection zone to 80% of its fracture pressure, thus major releases of seismic/acoustic energy attributable to the GS project are not anticipated. Nonetheless, micro-seismic events will likely be triggered at known/unknown minor non-transmissive faults and fractures within the injection zone as the pressure front advances or retreats throughout the reservoir. The signals associated with each micro-seismic event will be analyzed and verified by a qualified human seismologist, with verified events added to the event catalog for the GS project. Verification involves a manual review of each event detected by the automated system using a 1D velocity model in HYPOINVERSE[2] – a widely utilized software package distributed by the U.S. Geological Survey used for locating earthquakes and determining magnitudes in local or regional seismic networks. The event data are then transferred into an open-source software package based on the Advanced National Seismic System (ANSS) Quake Monitoring System (AQMS)[3] database– the real-time and post-processing wrapper around the Earthworm[4] automated earthquake detection software system

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2 See: HYPOINVERSE Earthquake Location 2019 at https://www.usgs.gov/software/hypoinverse-earthquake-location
3 See: https://www.isti.com/products-offerings/aqms
4 See: https://www.isti.com/products-offerings/earthworm

used by the United States Geological Survey (USGS), Kansas Geological Survey (KGS), and other regional seismic networks in the US. Figure E.11-1 is a screenshot of an event being manually picked and relocated using the graphical user interface (GUI) to the AQMS database. After verification, the hypocenters of the micro-seismic events will be plotted onto a three-dimensional subsurface projection to image subsurface areas undergoing deformation, thus tracking the pressure front over time.

The human seismologist also periodically reviews the data stream for events that were not detected by the automated process. This review is performed by examining the continuous time domain data in the frequency domain across multiple stations, searching for spectral hits that were not obvious in the time domain data. The left panel of Figure E.11-2 shows spectral plots for an obvious 0.6 local magnitude (M_L) event that was successfully identified by the automated system using time domain data. The right panel of Figure 11-2 shows spectral plots for a -0.6 M_L micro-seismic event that was originally missed by the automated system. Manual inspection of the spectral plot shows a small perturbation at roughly 09:32:30 across several stations, which was later verified and cataloged as a micro-seismic event.

PCC will deploy a passive seismic array consisting of nine 3-axis wide band seismometers installed in individual bores of roughly 100' depth across the areal extent of the AoR, MMA, and vicinity. Five of these seismometer installations coincide with the groundwater and soil gas monitoring stations for the GS project (i.e., MS-1 through MS-3, plus MS-5 through MS-6); the other four seismometers are located within their own monitoring stations MS-7 through MS-10.

Figure E.11-3 displays the technical performance of the passive seismic monitoring system. Events less than -1.5 M_W are detected across the entirety of the AoR and MMA, with the lower detection limit approaching -2 M_W in some locations. Vertical uncertainty is between 100-200 m (328-656 ft) across the entirety of the AoR and MMA. Horizontal uncertainty is less than 100 m (328 ft) across the entire AoR and much of the MMA.

See Section E.I.2.9 of the QASP for additional detail on the passive seismic array.

Figure E.11-1. Screenshot of Manual Event Picking in AQMS Database GUI

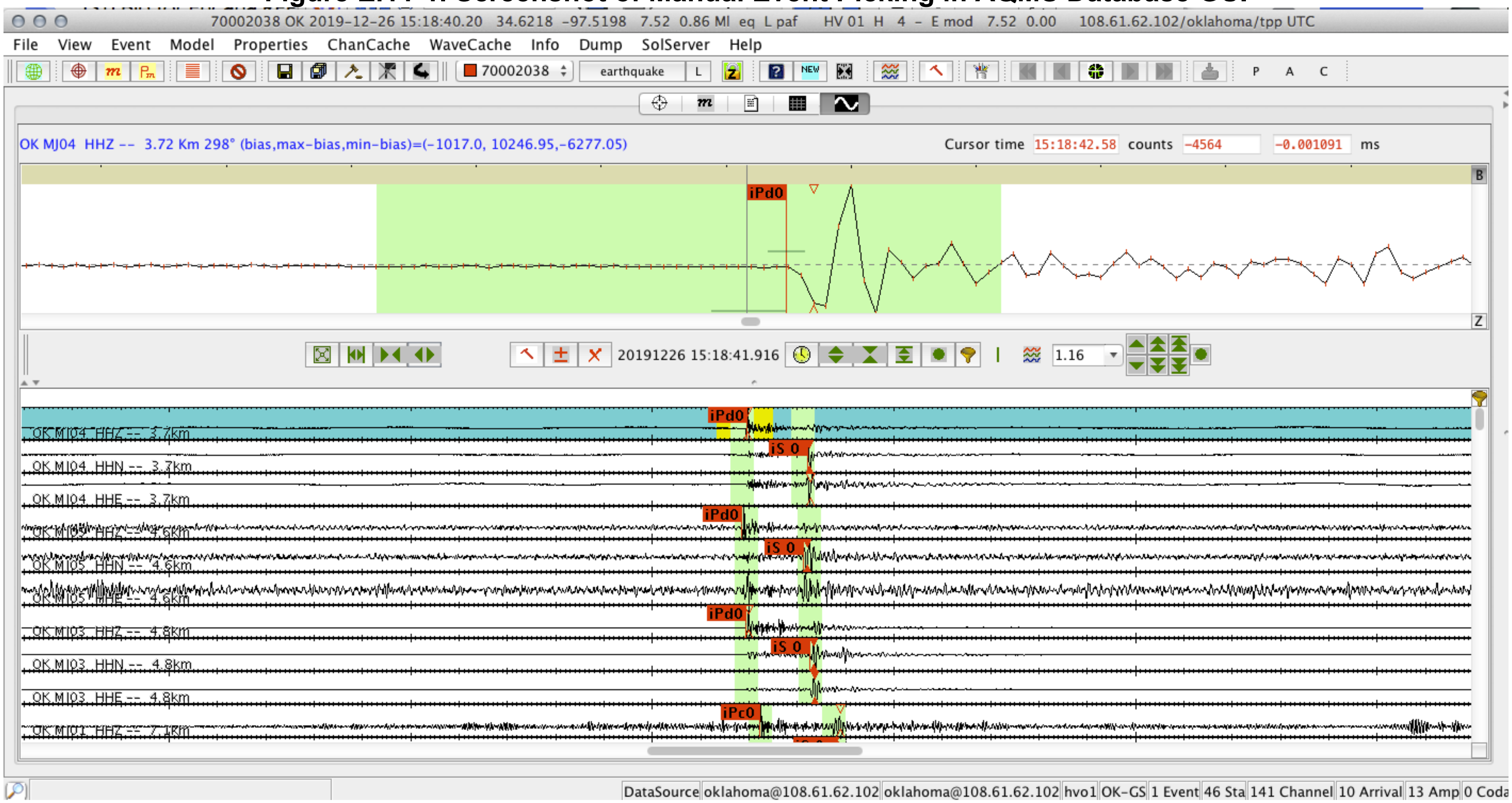


Figure E.11-2. Manual Review of Spectral Data Across Eight Stations
Left: Obvious 0.6 M_L Event at 16:33:00; Right: Less Obvious -0.6 M_L Event at 09:32:30

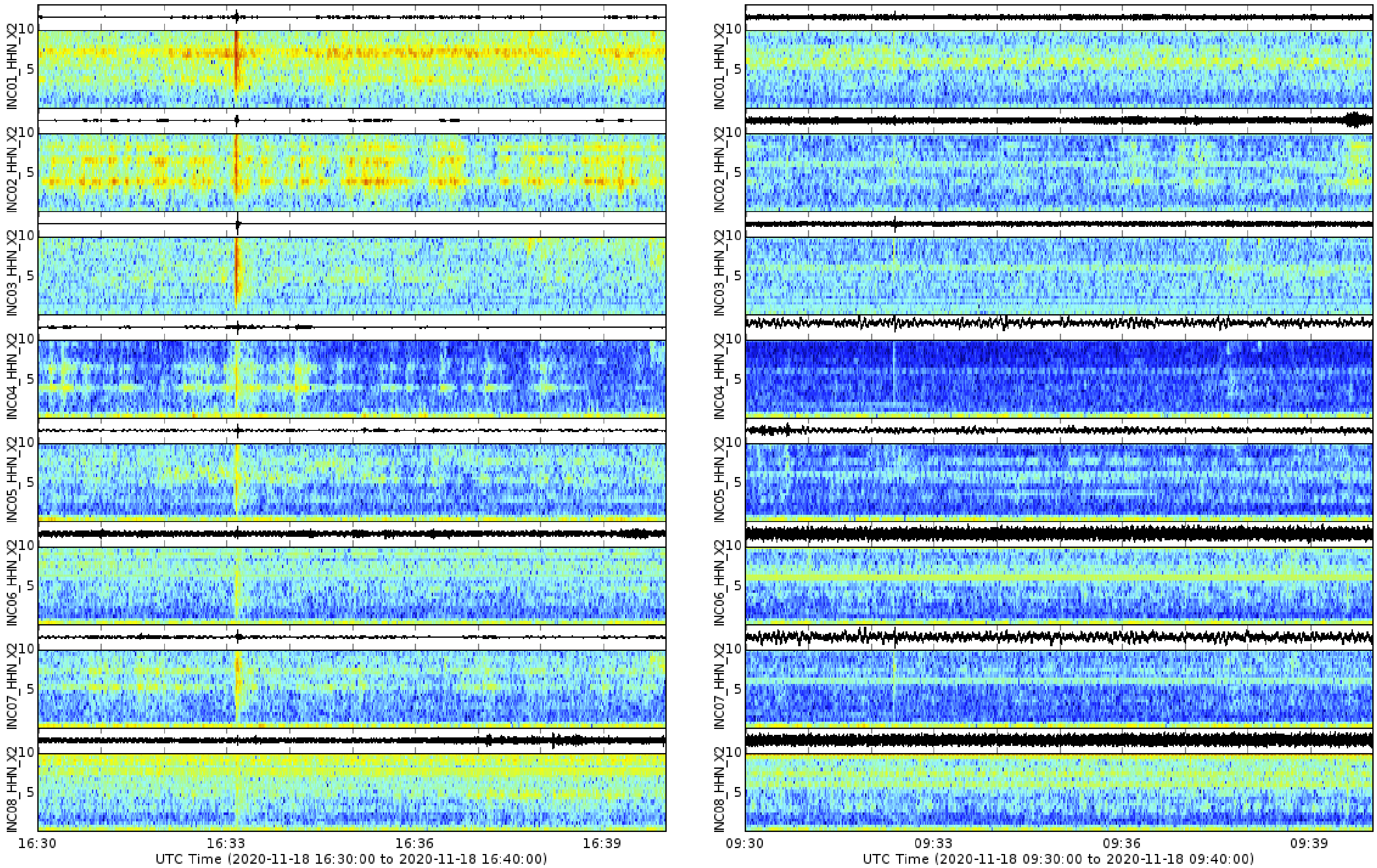
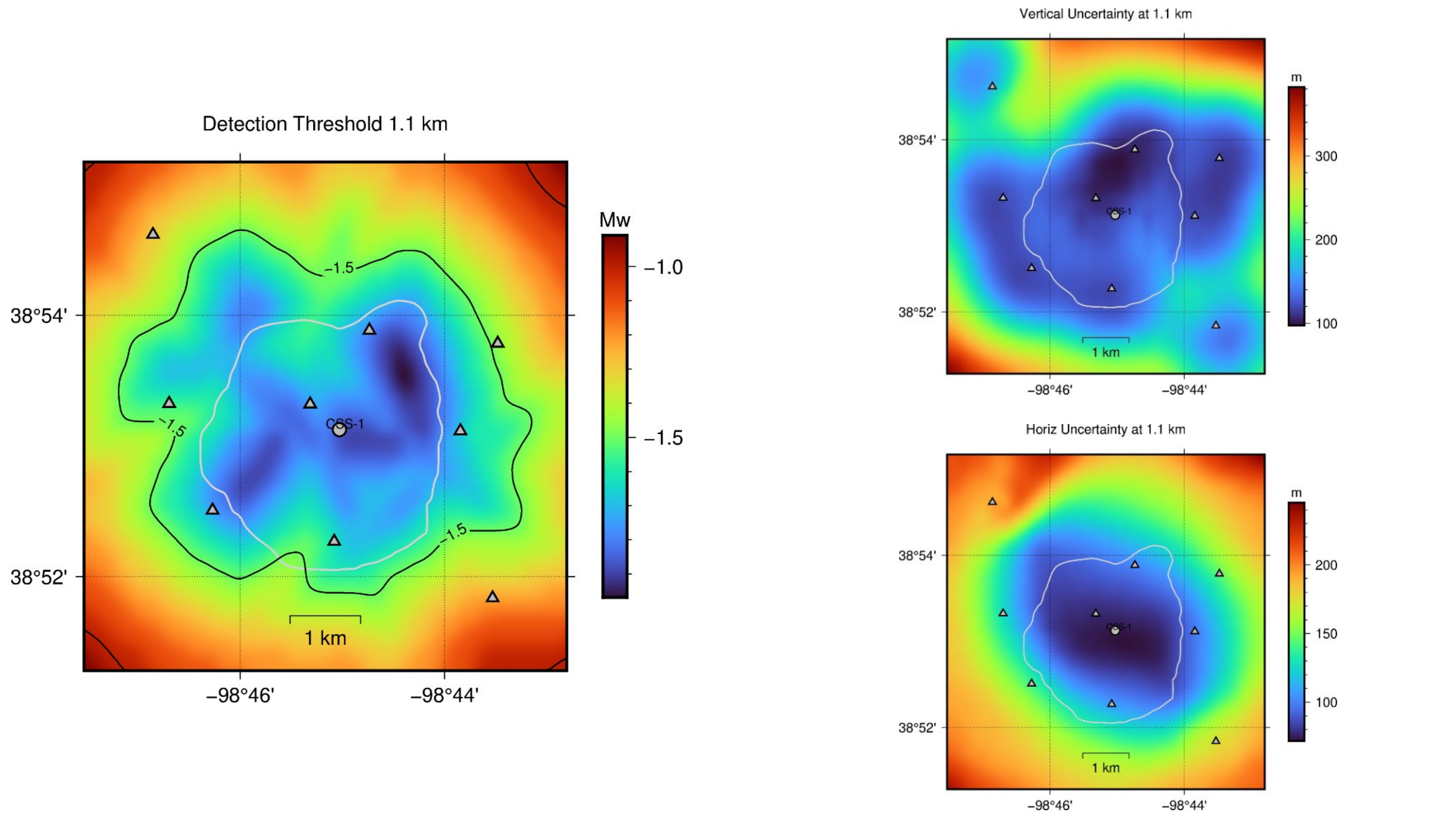


Figure E.11-3. Technical Performance of Passive Seismic Monitoring System

Pink Line: Areal Extent of AoR; Triangles: Seismometer Locations

Left: Detection Threshold; Upper Right: Vertical Uncertainty at 1.1 km; Lower Right: Horizontal Uncertainty at 1.1 km



E.12. Soil Gas Monitoring [Project-Specific Testing and Monitoring]

A preliminary review of common GS project risks and site-specific conditions by PCC identified the potential for CO_2 leakage to the surface as a scenario that may not be adequately addressed by the minimum testing and monitoring requirements of 40 CFR 146.90. PCC will implement a soil gas monitoring program to identify and quantify potential CO_2 leakage to the surface across the MMA as part of its risk mitigation strategy.

E.12.1. Monitoring Locations and Frequency

PCC has installed a network of 6 monitoring stations (MS-1 through MS-6) within and in the vicinity of the AoR and MMA as illustrated previously in Figure E.9-1. Each monitoring station contains CO_2 gas sensors for measuring CO_2 concentrations in the upper vadose zone at approximately 5 feet below ground surface (ft bgs) (SCSW-1 through SCSW-6) and in the lower vadose zone at approximately 10 ft bgs (DSCW-1 through DCSW-6), sampling vapor points to obtain soil gas grab samples in the upper vadose zone (SVP-1S through SVP-6S) and the lower vadose zone (SVP-1D through SVP-6D), and a set of 16 pre-installed soil collars at each station to simplify dynamic closed chamber (efflux) measurements at the surface. See Attachment A.II Well Construction Details for depths and other details for each soil gas monitoring well.

Soil gas CO_2 concentrations will be continuously monitored by CO_2 sensors equipped with data loggers placed in the upper and lower vadose zones. The data are transmitted during Pre-Injection, Injection, and Initial PISC periods to PCC (and its subcontractors) by telemetry to allow real-time remote access monitoring. Data loggers are also installed at each monitoring station for redundancy in case of a failure in the data transfer telemetry system. Soil gas grab samples from the sampling points in the upper and lower vadose zones will undergo laboratory analysis. Dynamic closed chamber (efflux) measurements of CO_2 concentration versus time will be made using a field infrared gas analyzer.

Table E.12-1 shows the planned monitoring locations and frequencies for soil gas monitoring. As discussed previously in Section E.9, the monitoring station locations were selected to provide broad coverage of the areal extent of the AoR and the MMA, and also were tailored to the specifics of the project site.

Table E.12-1. Monitoring Locations and Frequencies for Soil Gas Monitoring

Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Monitor soil gas CO_2 across a network of stations	SCSW-1, DCSW-1 SCSW-2, DCSW-2 SCSW-3, DCSW-3 SCSW-4, DCSW-4 SCSW-5, DCSW-5 SCSW-6, DCSW-6	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Continuous(1)
			Injection	Continuous(1)
			PISC	Initial: Continuous(1) Maintenance: Continuous(1) (data logger only)
Laboratory Analysis of Samples from Network of Stations	SVP-1S, SVP-1D SVP-2S, SVP-2D SVP-3S, SVP-3D SVP-4S, SVP-4D SVP-5S, SVP-5D SVP-6S, SVP-6D	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Annual
			Injection	Annual
			PISC	Initial: Annually Maintenance: Every 5 years
CO_2 Efflux Measurements at Each Station	MS-1, MS-2 MS-3, MS-4 MS-5, MS-6	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Annual
			Injection	Annual
			PISC	Initial: Annually Maintenance: Every 5 years

Note 1: Continuous is defined as measurements taken at 30-minute intervals, with a 6-hour average reading recorded

E.12.2. Analytical Parameters

Table E.12-2 lists the analytes and analytical methods used for laboratory analysis of soil gas grab samples from the upper and lower vadose zones.

Table E.12-2. Summary of Analytical Parameters for Soil Gas Grab Samples

Analyte	Analytical Method
Argon	ASTM D1945 modified or similar/equivalent
Oxygen	ASTM D1945 modified or similar/equivalent
Nitrogen	ASTM D1945 modified or similar/equivalent
Carbon Dioxide	ASTM D1945 modified or similar/equivalent
Methane	ASTM D1945 modified or similar/equivalent
δ^{13} C of CO_2	SRI 8610C
Methane - field	Field meter (LANDTEC GEM5000 or equivalent) - dual wavelength infrared cell with reference channel
Carbon Dioxide - field	Field meter (LANDTEC GEM5000 or equivalent) - dual wavelength infrared cell with reference channel
Oxygen - field	Field meter (LANDTEC GEM5000 or equivalent) - internal electrochemical cell

E.12.3. Sampling Methods

Sampling methods and sample preservation will be performed as described in Section E.I.2.2 of the QASP.

E.12.4. Laboratory to be Used/Chain of Custody Procedures

Sample handling and custody are described in Section E.I.2.3 of the QASP. Laboratory analytical methods are described in Section E.I.2.4 and Appendix D of the QASP. Field quality control is described in Section E.I.2.5 of the QASP.

E.13. Ecosystem Stress Monitoring [Project-Specific Testing and Monitoring]

A preliminary review of common GS project risks and site-specific conditions by PCC identified the potential for CO_2 leakage to the surface as a scenario that may not be adequately addressed by the minimum testing and monitoring requirements of 40 CFR 146.90. PCC will implement an Ecosystem Stress Monitoring program to identify and quantify CO_2 leakage to the surface across the MMA as part of its risk mitigation strategy.

The general principle behind ecosystem stress monitoring is that the presence and overabundance of CO_2 resulting from potential surface leakage or seepage will have an observable and measurable impact on vegetative plant health. Spectral imagery methods are a common technique for detecting stressed vegetation since it has an identifiable spectral signature caused by chlorophyll absorbing less visible spectral wavelength radiation and reflecting less energy near the infrared wavelengths (Rouse et al., 2010). Furthermore, remote sensing spectral methods can also distinguish between impacts caused by CO_2 as compared to precipitation, hail, or herbicide applications through examination of response timing differences (Rouse et al. 2010; Verkerke et al. 2014; Yahaya et al. 2011).

PCC retained several professors from the Kansas Applied Remote Sensing (KARS) Program at the University of Kansas to assist with development and data evaluation for a satellite-based ecosystem stress monitoring program utilizing both historical and future spectral data as an indicator of vegetation health across an area of interest around the GS site, approximately 4 miles by 4 miles square inclusive of the AoR and MMA. The KARS team will specifically assist with obtaining and processing the multi-spectral satellite imagery.

The PCC's consultant and the KARS team provided some preliminary charts as part of their services proposal to PCC. Figure E.13-1 provides current vegetation covers of land around the GS site based on the State of Kansas ecological land coverage map, which will be used as the primary basis for vegetation field verification surveys. Figure E.13-2 provides example multispectral normalized difference vegetation index (NDVI) imagery for early July through early August 2023 which coincides with the desired annual peak month period.

Figure E.13-1. Vegetation Coverage Map

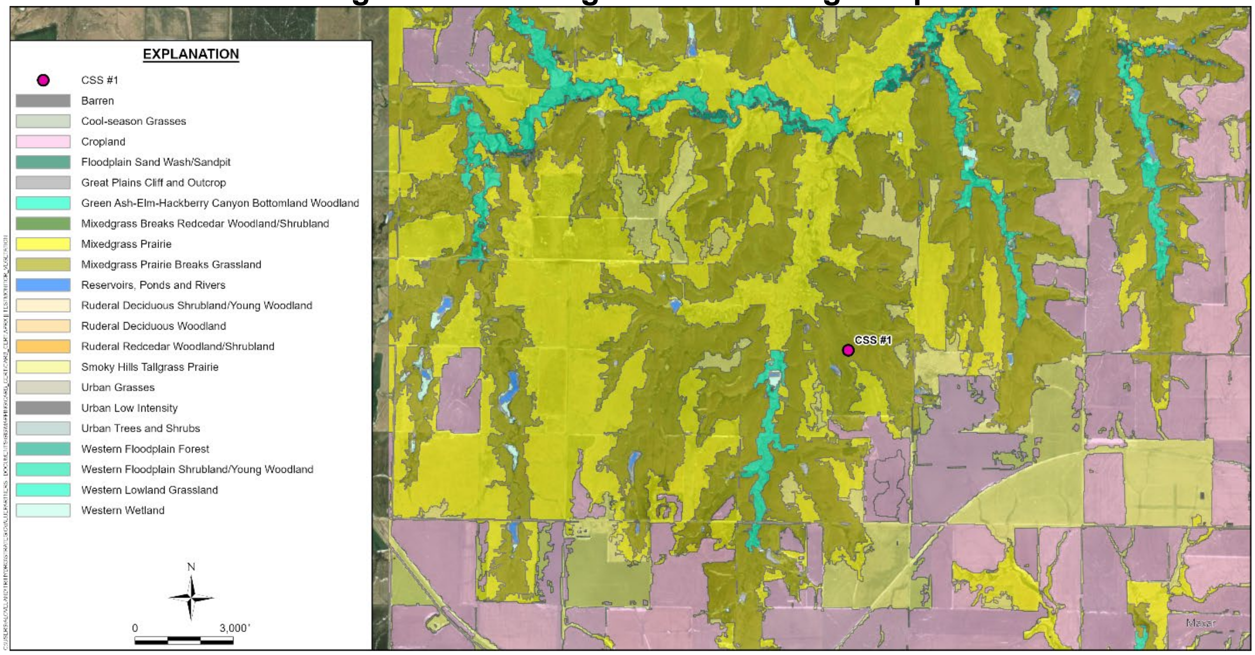
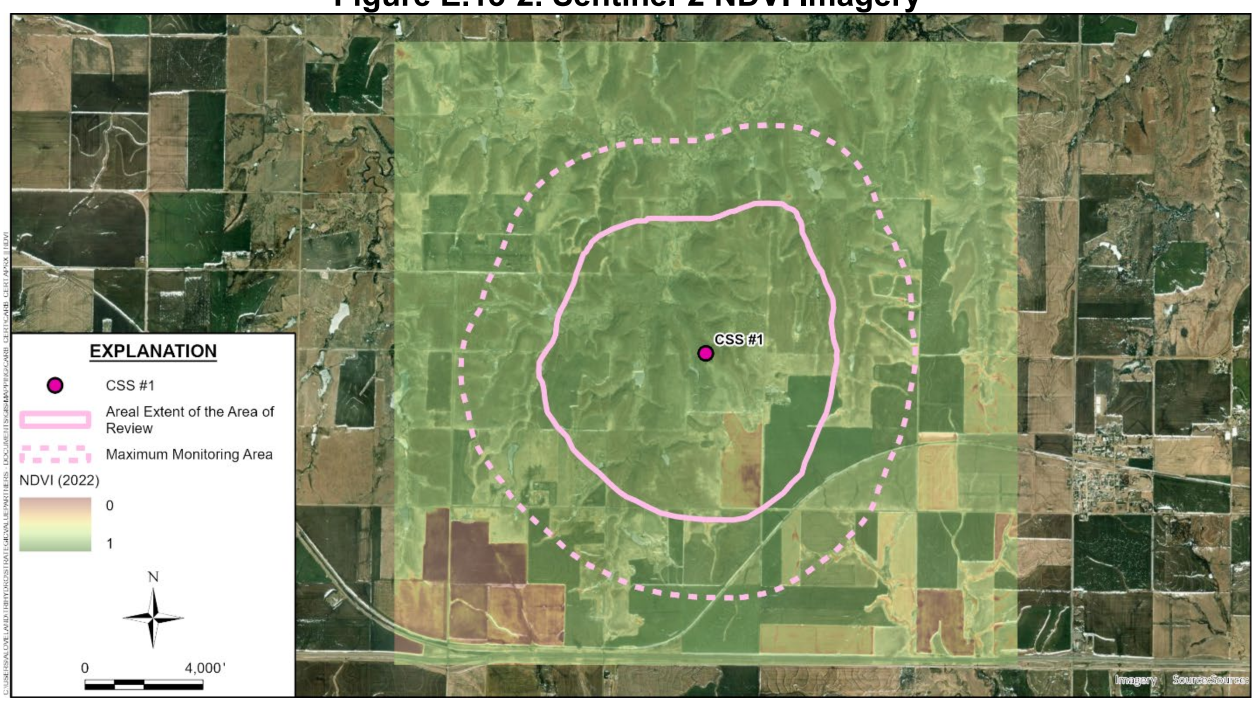


Figure E.13-2. Sentinel-2 NDVI Imagery



A bulleted summary of the overall ecosystem monitoring program includes the following steps:

- The KARS team will access and process high resolution (10-meter [roughly 33-feet] pixel resolution) Sentinel-2 satellite imagery data. These data provide higher spatial resolution and more accurate location data, as compared to other older satellite 30-m pixel imagery data sets. These data will be obtained over an approximate four mile by four mile remote sensing area of interest that includes the GS AoR and MMA.
- PCC's consultant will work with the KARS team to identify selected target areas/control sites (roughly 30 to 40 sites) across the study area. The selection of these target/control areas will consider different factors such as different vegetation types (~20 verification sites), proximity to existing monitoring station (~6 to 10 target sites), potential CO_2 preferential migration pathways (~16 former O&G well target sites, and potential receptors. Each target area will include a three-pixel by three-pixel square (~30 m x 30 m {~100 ft x 100 ft}). These target/control sites will initially be selected using desktop GIS methods, and if necessary, may be adjusted (shifted) slightly during the field verification to avoid and minimize unnatural vegetation disturbance (e.g., roads, fence lines, agricultural activities).
- The KARS team will extract and evaluate the historical remote sensing (satellite) multi-spectral data, specifically the NDVI from the initiation of the Sentinel-2 imagery data. The historical NDVI data (2016 through 2022) will be used to calculate a long-term mean, and the current year (2023 year-to-date) NDVI data will also be calculated. Collectively the long-term mean NDVI data will be used to establish a set of baseline NDVI conditions for future annual review comparisons.
- Table E.13-1 provides a summary of the month NDVI data evaluation that includes a long-term monthly mean NDVI value based on the available data from the satellite imagery data, it also includes monthly NDVI values for 2023 year-to-date. These NDVI and subsequent data evaluation are based upon satellite imagery data extracted for the five primary, natural vegetation types occurring within the remote sensing area of interest, and they include in descending order: mixed grass prairie breaks, mixed grass prairie, smoky hills tall grass prairie, western lowland grassland, and woodlands (actually a composite of several different woodland vegetation types). Croplands that are being actively cultivated or used for agricultural purposes will be excluded from the remote sensing data evaluations to the extent possible, as they will obviously be experiencing substantial change on a yearly basis.
- Figure E.13-3 provides graphical illustration of these NDVI data including the 2023 year-to-date (YTD), the long-term historical mean, along with the standard deviation for the historical mean. This graph and these data indicate a couple of key points: (1) the historical annual peak biomass period for the remote sensing area of interest occurs from the last week in June through the first week in August, and (2) the 2023 YTD NDVI are well below the historical mean and even outside the lower most standard deviation. This recent departure from the historical data trends is most likely occurring due to the severe drought condition that this region in Kansas experienced in early 2023. This observation warrants incorporating an evaluation and comparison to naturally occurring historical data trends into the remote sensing monitoring program.

- To assist with such future remote sensing data evaluations, the KARS team will also extract and evaluate peak month temperature/precipitation satellite data that coincides with the current year and long-term mean data sets. These meteorological data will provide additional insight into potential vegetation changes and differences. Other factors that will be evaluated to understand the potential vegetation changes will also include soil conditions, surface geology, and surface topography/geomorphology.
- Some of the future work products resulting from these remote sensing data evaluations and monitoring program will include:
  - Data evaluations will be performed for the entire project site in general, selected vegetation types/classes (if warranted based on VI value differences), and for the selected target areas/control sites.
  - Peak month multispectral vegetation indices maps – NDVI.
  - Compute the annual (current year) and the long-term Peak Month, if data available, NDVI values and statistics.
  - Compare the current year data to the most recent past year, long-term background/baseline data and trends, compare current year VI data obtained inside and outside the anticipated AoR, and potential additional statistical analyses as warranted.
- The ecological field team performed a vegetation field verification survey during the peak month period (first week of August 2023) to confirm the existing vegetation/land use coverage data illustrated in Figure E.13-1 and to confirm the approximate 40 planned target/control areas to be used as part of the future remotes sensing vegetation evaluation. During these field verification efforts, the field ecology team walked routine North-South and East-West transects through the target control areas, documented the dominant vegetation types, completed a standard site inspection/verification field form, and took site specific photos. These data along with the associated remote sensing data from the KARS team will be maintained in project and task specific database that will also include the dates of these field surveys and the names of the ecologists completing the field tasks.
- Subsequently, on a recurring annual basis, the KARS team will complete the remote sensing data analysis of the satellite imagery data within the peak biomass (monthly) period and detailed comparisons for the differences or changes observed across the project site (inside/outside the AoR), different vegetation types/classes (as warranted), for the selected target areas/control sites, and departures from previous historical trends.
- If a potential vegetative anomaly is identified, a focused evaluation of those specific areas will be conducted and may include using the various methods described above and may be expanded to include comparisons of other near-surface (e.g., CO_2 efflux, soil gas, and groundwater) monitoring data. Additionally, if deemed necessary/appropriate, evaluating other multispectral VIs satellite imagery data, in addition to NDVI may also be performed. Careful evaluation and consideration of these supplemental data, including the vegetation response timing, will be conducted to confirm the potential of an actual CO_2 leak/seepage and to reduce the probability of identification of false-positives as potential CO_2-related anomalies.

Table E.13-1. Identify the Annual Peak-Month with Vegetation NDVI Data

NDVI Composite Period end date	NDVI Value 2023 Year-to-Date	NDVI Value Long-term Mean (2016-2022)	NDVI Value + SD Long-term Mean	NDVI Value - SD Long-term Mean
10-Jan-23	0.11	0.195	0.219	0.171
20-Jan-23	0.095	0.191	0.214	0.168
30-Jan-23	0.095	0.187	0.215	0.16
9-Feb-23	0.1	0.173	0.21	0.136
19-Feb-23	0.098	0.17	0.192	0.148
1-Mar-23	0.098	0.156	0.183	0.13
11-Mar-23	0.097	0.157	0.184	0.13
21-Mar-23	0.103	0.138	0.181	0.095
31-Mar-23	0.104	0.143	0.187	0.099
10-Apr-23	0.106	0.166	0.199	0.133
20-Apr-23	0.108	0.175	0.211	0.139
30-Apr-23	0.115	0.206	0.258	0.154
10-May-23	0.117	0.223	0.277	0.169
20-May-23	0.138	0.283	0.361	0.206
30-May-23	0.14	0.346	0.428	0.263
9-Jun-23	0.245	0.433	0.528	0.339
19-Jun-23	0.276	0.458	0.537	0.379
29-Jun-23	0.29	**0.477**	0.558	0.397
9-Jul-23	0.308	**0.474**	0.551	0.398
19-Jul-23	0.336	**0.48**	0.561	0.4
29-Jul-23	0.337	**0.485**	0.573	0.397
8-Aug-23	0.33	**0.473**	0.579	0.368
18-Aug-23	0.316	0.442	0.561	0.324
28-Aug-23	0.311	0.39	0.546	0.234
7-Sep-23	0.312	0.428	0.557	0.298
17-Sep-23		0.42	0.557	0.284
27-Sep-23		0.419	0.55	0.288
7-Oct-23		0.4	0.529	0.271
17-Oct-23		0.385	0.495	0.275
27-Oct-23		0.359	0.456	0.262
6-Nov-23		0.309	0.385	0.234
16-Nov-23		0.264	0.339	0.19
26-Nov-23		0.219	0.294	0.144
6-Dec-23		0.2	0.254	0.145
16-Dec-23		0.193	0.249	0.136

Notes:

1) Normalized difference vegetation index (NDVI) is calculated using the near infrared (NIR) and red channel multispectral data - NDVI = (NIR - Red)/(NIR + Red) obtained from the Sentinel-2 multispectral satellite

2) NDVI values are an indication of the general vegetation health and biomass and may range from 0 to +1 , with the more positive values representing more healthy vegetation more biomass

3) For these NDVI calculations, the highest NDVI values used for the above calculations were based upon the five most dominant natural vegetation types present within the approximate 4 mile by 4 mile evaluation area.

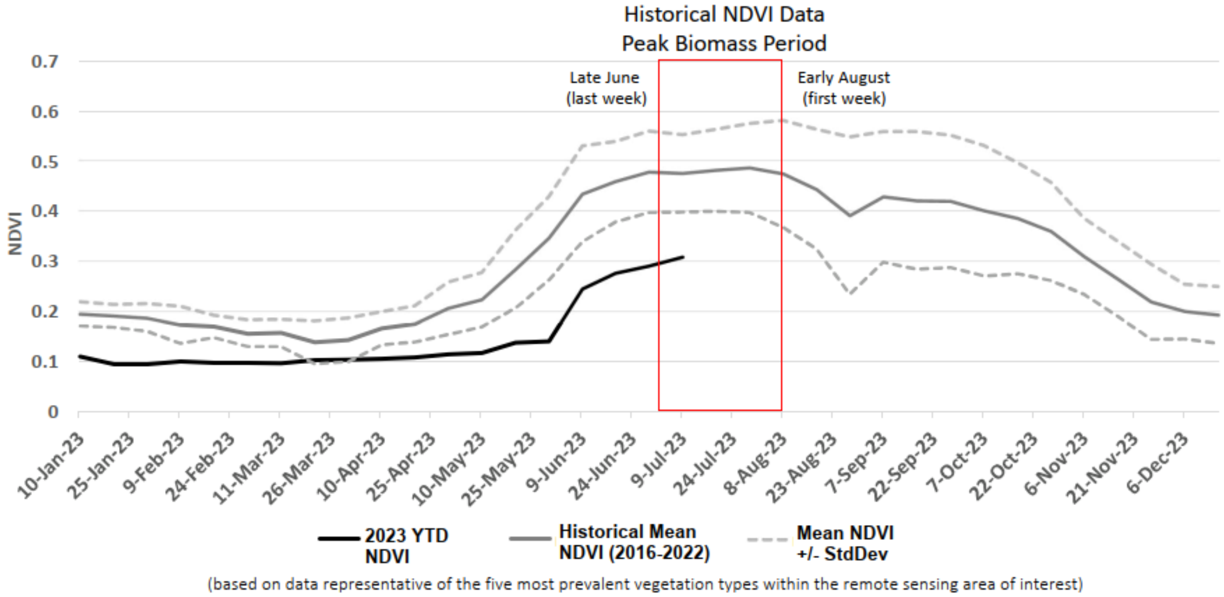
4) The highest NDVI values from a composite 30-day imagery data set are used for this analysis, and these data are updated on a 10-day repeat cycle, based on the Sentinel-2 satellite repeat orbit frequency

5) The statistics, mean and standard deviation (SD), for these NDVI values were evaluated and determined using the entire available period of record (2016 {launch} -2022) for the Sentinel-2 satellite imagery data

6) The bold and shaded section indicates long-term peak month NDVI (plant health/biomass) from the available Sentinel-2 satellite imagery data

Source: KARS 2023 and Trihydro 2023

Figure E.13-3. Sentinel-2 NDVI Historical Data Peak-Month Evaluation



E.14. Surface Air Monitoring [Project-Specific Testing and Monitoring]

A preliminary review of common GS project risks and site-specific conditions by PCC identified the potential for CO_2 leakage to the surface as a scenario that may not be adequately addressed by the minimum testing and monitoring requirements of 40 CFR 146.90. PCC will implement a surface air monitoring program as part of its risk mitigation strategy.

E.14.1. Monitoring Locations and Frequency

Table E.14-1 shows the planned monitoring location and frequencies for the surface air monitoring program. The plan consists of two components: (a) Continuous monitoring of the CO_2 concentration in surface air at the wellheads for CSS #1 and MW #1, with telemetry to provide operations with real time monitoring data and alarms, plus data loggers for redundancy, and (b) Periodic surveys of the wellheads and above surface piping within 100’ of the wellheads using an audio, visual, and olfactory (AVO) inspection to observe potential CO_2 leaks.

Table E.14-1. Monitoring Locations and Frequencies for Surface Air Monitoring

Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Surface Air Concentration of CO_2	CSS #1, MW #1	Single Point Measurement at Wellhead	Pre-Injection	Not Applicable
			Injection	Continuous
			PISC	Initial: Continuous Maintenance: Continuous (data logger only)
AVO Inspection of Wellhead and Surface Piping	CSS #1	Wellhead, Above Surface Piping Within 100' Radius of Wellhead	Pre-Injection	Not Applicable
			Injection	Quarterly
			PISC	Not Applicable

E.14.2. Analytical parameters

Surface air concentrations of CO_2 (the analyte) will be monitored using a non-dispersive infra-red (NDIR) sensor installed in the air at the wellheads.

An AVO inspection utilizes the human senses (hearing, sight, smell) to detect leaks.

E.14.3. Sampling Methods

The CO_2 sensors installed at the wellheads continuously sample air at the sensor point.

Appendix E.I.5 of the QASP provides a standard operating procedure for conducting an AVO Inspection of the CSS #1 wellhead and surface piping.

E.15. Seismic Monitoring [Project-Specific Testing and Monitoring]

PCC will implement a seismic monitoring plan to identify seismic risks, and use the results of the seismic monitoring program to guide the respond to seismic events as described in Section H.4.5 of the Emergency and Remedial Response Plan. The monitoring and response plans are both aligned with the Kansas Seismic Action Plan (Kansas 2015) that state-level agencies use to regulate UIC wells in the state. The KGS operates a state-wide seismic monitoring network and maintains a database of past seismic events in the state. KGS provides seismic event information to the Kansas Department of Health and Environment (KDHE) that regulates UIC Class I and UIC Class III-V wells in the state, and also provides seismic event information to the Kansas Corporation Commission (KCC) that regulates UIC Class II wells in the state. The Kansas Seismic Action Plan defines state agency response to seismic events, including regulatory remedies available to the agencies under current statutory authorities.

Three seismic networks will be monitored in the GS project: the aforementioned KGS regional seismic network, the United States Geological Survey (USGS) ANSS regional network, and the dedicated local passive seismic network for the GS project described earlier in Section E.11. All three networks will be continuously monitored upon installation of the dedicated local network during the Pre-Injection period (upon installation of the dedicated local network) through the Initial PISC period. The dedicated local network will be retired during the Maintenance PISC period, but monitoring of the two regional networks will continue until Site Closure.

This project is aligned with the implementation of the Kansas Seismic Action Plan in regard to the role that qualified human seismologists play. Earthquake monitoring networks are highly automated, but unfortunately the automated systems sometimes generate false-positive event indications. KGS does not add an event into its catalog until it has been verified by a qualified human seismologist in order to eliminate false-positive indications generated by their automated monitoring system. KGS notifies KDHE and KCC of any verified events that exceed thresholds, then KDHE and KCC implement their response plans to the event. Likewise for this GS project, an emergency shutdown response is initiated only for events that have been verified by a qualified human seismologist.

A triggering event is defined in this project and in the Kansas Seismic Action Plan as a seismic event of 2.0 M_L or greater (as reported by the PCC dedicated passive seismic network) with an epicenter located within a 6-mile radius of CSS #1. To improve clarity, this project uses the term “verified triggering event” to explicitly indicate a triggering event that has been validated by a qualified human seismologist, while the term “triggering event” is more general in that it may describe either: a) un-verified triggering event as directly reported by the automated networks, or b) a verified triggering event.

A Seismic Action Score (SAS) will be computed for each triggering event using the formula provided in the Kansas Seismic Action Plan. The SAS formula combines event magnitude with scoring for risk variables plus scoring for clustering and timing variables. Risk variables account for risk of property damage from the event (i.e., larger values for risk variables result from higher risk for property damage). Clustering and timing variables are used to discriminate between natural and induced seismic events. Seismic events clustered over a short time period in a fashion inconsistent with historical activity are indicative of induced seismicity, thus values assigned to clustering and timing variables are larger for events that appear to be induced seismic events.

The SAS is computed by the formula below with rounding to the nearest first decimal place:

$$SAS = (Magnitude)^2 + Score_{felt} + Score_{structure} + 2(Score_{number})^3 + (Score_{local\ recurion})^3 + Score_{recursion\ regional} + Score_{recurion\ time}$$

where:

Magnitude = Event magnitude reported by the networks, M_L

with the risk variables defined as:

$Score_{felt}$ = Assigned of the following values based on the USGS "Did You Feel It" website at https://earthquake.usge.gov/data/dyfi/
0, if the event is not registered within 24 hours on the USGS "Did You Feel It" web site
1, if the event is registered within 24 hours on the USGS "Did You Feel It" web site

$Score_{structure}$ = Assigned one of the following values (should always be 1)
0, if the event is > 6 mile distant from CSS #1 or MW #1
1, if the event is ≤ 6 mile distant from CSS #1 or MW #1

and the clustering and timing variables defined as:

$Score_{number}$ = Assigned one of the following variables based on qualifying past events, where a qualifying past event is defined as an event larger than 2.0 M_L that occurred within the past 30 days within a 6-mile radius of CSS #1
0, if there are no qualifying past events
1, if there is one qualifying past event
2, if there are two qualifying past events
3, if there are three qualifying past events
4, if there are four or more past qualifying events

$Score_{local\ recursion}$ = Assigned one of the following values based on the empirical observation that that naturally occurring seismicity occurs in an exponential manner – every seismic event of 3 M_L would be preceded by ten events of 2 M_L and one hundred events of 1 M_L. Evaluating the $Score_{local\ recursion}$ term requires access to a databank of statistically significant historical events within a 6-mile radius of the injection well, which for this project is built upon the two regional network databanks (KGS, USGS ANSS) plus entries recorded by the local seismic network.
0, if event fits within local recursion pattern for natural seismic events
1, if event does not fit within local recursion pattern for natural seismic events

$Score_{recursion\ regional}$ = Assigned one of the following values based on the same criterion as for evaluation of $Score_{local\ recursion}$ except the 6-mile radius region of interest for historical events is replaced with all data for Kansas recorded over the 35 plus years on the KGS database.
0, if event fits within regional recursion pattern for natural events
1, if event does not fit within regional recursion pattern for natural events

$Score_{recursion\ time}$ = Assigned one of the following values based on qualifying past events, where a qualifying past event is defined as an event with ± 0.5 M_L of the triggering event and the past event occurred within the past 24 hours and within a 6-mile radius of CSS #1 or MW #1
0, if there are no qualifying past events
1, if there is one qualifying past event
2, if there are two qualifying past events
3, if there are three qualifying past events
4, if there are four or more qualifying past events

Section H.4.5 of the Emergency and Remedial Response Plan provides a three-level (green, yellow, red) stoplight system to guide the response to seismic events. Emergency shutdown plans are implemented when one or more verified triggering events have occurred with the past 24 hours that are either ≥ 3.5 M_L or SAS ≥ 17. It is instructive to examine the outcomes for two events of 2.7 M_L with different circumstances. The left columns in Table E.15-1 computes SAS for the Single Event case as 8.2 using "best-case" circumstances indicative of a natural seismic event; in this example, injection operations can continue since the reviewed triggering event was < 3.7 M_L and SAS was < 17. The right columns in Table E.15-1 computes SAS for the Cluster Event case as 143.3 using "worst-case" circumstances indicative of an induced seismic event; in this example, an emergency shutdown is initiated since the reviewed triggering event has SAS ≥ 17 even though the individual event is not ≥ 3.5 M_L. These examples demonstrate the ability to discriminate between natural and induced seismic events using the framework adopted by this project and the Kansas Seismic Action Plan.

Table E.15-1. SAS for Two Triggering Events of 2.7 M_L

Term	Single Event		Cluster Event	
	Value	SAS Contribution	Value	SAS Contribution
Magnitude, M_L	2.7	7.3	2.7	7.3
$Score_{felt}$	0.0	0.0	1.0	1.0
$Score_{structure}$	1.0	1.0	1.0	1.0
$Score_{number}$	0.0	0.0	4.0	128.0
$Score_{local\ recursion}$	0.0	0.0	1.0	1.0
$Score_{recursion\ regional}$	0.0	0.0	1.0	1.0
$Score_{recursion\ time}$	0.0	0.0	4.0	4.0
	SAS Total	8.3	SAS Total	143.3

E.16. References

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