SECTION E. TESTING AND MONITORING PLAN
40 CFR 146.90

MONTEZUMA NORCAL CARBON SEQUESTRATION HUB

Facility Information

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Partial List of Abbreviations and Acronyms

°C = Celsius	MIT = mechanical integrity test
3D = three-dimensional	mm = millimeters
American Society of Testing Materials	MMA = maximum monitoring area
ANSI = American National Standards Institute	MPa = megapascal
AoR = area of review	
BuriedArray = BuriedArray® system	ms = millisecond
CDT DL = conductivity, depth, temperature data	Mw = Magnitude
logger	MW = monitoring well
cm = centimeter	m^3/hr = cubic meters per hour
CO_2 = carbon dioxide	OA = oxygen activation
DAS = distributed acoustic sensors	PISC = post-injection site care
DSS = distributed strain sensors	psi = pounds per square inch
DTS = distributed temperature sensors	psi/ft – pounds per square inch (lateral) per foot
°F = Fahrenheit	(vertical)
ft = feet	QASP = Quality Assurance and Surveillance
ft bgs = feet below ground surface	Plan
GNSS = Global Navigation Satellite System	UC Berkeley = University of California
GPa = gigapascal	Berkeley

GS = geologic sequestration	UIC = Underground Injection Control
InSAR = Interferometric Synthetic Aperture Radar	USDW = Underground Source of Drinking Water
kg/hr = kilograms per hour	US EPA = United States Environmental Protection Agency
kg/m^3 = kilograms per cubic meter	VSP = vertical seismic profiling
kPa = kilopascal	
km = kilometers	
lbs/gal = pounds per gallon	
LBNL = Lawrence Berkeley National Laboratory	
m = meter	
M_c = magnitude of completeness	
MC = Montezuma Carbon	

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E.1 INTRODUCTION

This Testing and Monitoring Plan describes how Montezuma Carbon, LLC (MC) will monitor the Montezuma Carbon Sequestration Hub pursuant to 40 CFR 146.90. In addition to demonstrating that 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 Sources of Drinking Water (USDWs), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

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

Where applicable, the "Initial PISC" period is estimated to be the first 5 years after injection and the "Maintenance PISC" period is estimated to be the remaining 45 years.

E.1.1 QUALITY ASSURANCE PROCEDURES

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities pursuant to 40 CFR 146.90(k) is provided in Appendix E.I to this Testing and Monitoring Plan.

E.1.2 REPORTING PROCEDURES

MC will report the results of all testing and monitoring activities to the United States Environmental Protection Agency (US EPA) in compliance with the requirements under 40 CFR 146.91.

E.2. CARBON DIOXIDE STREAM ANALYSIS [40 CFR 146.90(A)]

MC 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.2.1 SAMPLING LOCATION AND FREQUENCY

Prior to startup and authorization for CO_2 injection, initial grab samples for laboratory analysis will be collected from the different CO_2 source facilities. Following construction and completion of the CO_2 transportation pipeline, grab samples for laboratory analysis will be taken from a designated sampling station located in the compressor building. All CO_2 stream sampling efforts and analysis will be completed in conformance with the requirements of 40 CFR 98.444(b)(3).

Routine chemical sampling will take place initially prior to injection authorization, and then subsequently on a quarterly interval, based upon the date of authorization to inject, at the following frequencies each year: 3 months, 6 months, 9 months, and 12 months. Sampling for isotope analysis by the laboratory will occur initially and then again once every five years.

MC will sample and analyze the CO_2 stream as described below.

E.2.2 ANALYTICAL PARAMETERS

MC will analyze the CO_2 for the constituents identified in Table E-1 using the methods listed.

TABLE E-1. SUMMARY OF ANALYTICAL PARAMETERS FOR CO_2 GAS STREAM

Parameters	Analytical Methods [1]
Oxygen	ISBT 4.0 (GC/DID)
Nitrogen	ISBT 4.0 GC/DID
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Total Hydrocarbons	ISBT 10.0 THA (FID)
Methane	ISBT 10.1 (GC/FID)
Acetaldehyde	ISBT 11.0 (GC/FID)
Sulfur Dioxide	ISBT 14.0 (GC/SCD)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Ethanol	ISBT 11.0 (GC/FID)
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

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

E.2.3 SAMPLING METHODS

CO_2 stream sampling will occur in the compressor building after the last stage of compression. A designated sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory. Representative samples will be taken at the designated sample station using equipment and preservation techniques given in Section E.I.2.2.5.F of the QASP.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers.

E.2.4 LABORATORY TO BE USED/CHAIN OF CUSTODY PROCEDURES

The sample chain-of-custody procedures described in the Section E.I.2.3 of the QASP will be followed.

E.3 CONTINUOUS RECORDING OF OPERATIONAL PARAMETERS [40 CFR 146.88(E)(1), 146.89(B) AND 146.90(B)]

MC 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, and 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.3.1 MONITORING LOCATION AND FREQUENCY

MC will perform the activities identified in Table E-2 to verify internal mechanical integrity of the injection well and to monitor injection pressure, rate, volume and annular pressure as required at 40 CFR 146.88, 146.89, and 146.90(b). All monitoring will be continuous for the duration of the operation period, and at the locations shown in the table. The injection well will have pressure/temperature gauges at the surface and in the tubing at the packer. In addition, there will be distributed temperature, strain, and seismic sensing (DTS, DSS, DAS), fibers in the injection well.

TABLE E-2. SAMPLING LOCATIONS FOR CONTINUOUS MONITORING.

Test Description	Location
Annular Pressure Monitoring	Surface
Injection Pressure Monitoring	Surface
Injection Pressure Monitoring	Reservoir - Proximate to packer
Injection Rate Monitoring	Surface
Injection Volume Monitoring	Surface
Temperature Monitoring	Surface
Temperature Monitoring	Reservoir - Proximate to packer
Temp, Strain, Seismic Monitoring	Along wellbore to packer using DTS, DSS, DAS

E.3.2 MONITORING DETAILS

Above-ground pressure and temperature instruments shall be calibrated over the full operational range at least annually using American National Standards Institute (ANSI) or other recognized standards. In lieu of removing the injection tubing, downhole gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Pressure transducers shall have a drift stability of less than 1 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once per 5 seconds. Temperature sensors will be accurate to within one degree Celsius. The DTS sampling rate will be once per 10 seconds. DTS/DSS sampling rate will be at least once per 10 seconds. DAS rates will be at least once per 10 milliseconds (ms).

Flow will be monitored with a Coriolis mass flowmeter at the compression facility. The flowmeter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flowmeter will be calibrated for the entire expected range of flow rates.

E.3.3 INJECTION RATE AND PRESSURE MONITORING

MC will monitor injection operations using the distributive process control system as presented below.

The Surface Facility Equipment & Control System are currently undergoing engineering development and design which is not yet completed. When finished, this equipment will be able to limit the CO_2 injection to designated not to exceed maximum flow and/or limit the well head pressure to the appropriate regulatory requirement not to exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the MC operations staff using the distributive process control system. This system will continuously monitor, control, and record data. The system will alarm and shut down if specified control parameters exceed their normal operating range.

More specifically, all critical system parameters, (e.g., pressure, temperature, and flow rate) will have continuous electronic monitoring with signals transmitted back to a master control system. MC supervisors and operators will have the capability to monitor the status of the entire system from one or more distributive control centers.

E.3.3.1 CALCULATION OF INJECTION VOLUMES

Flow rate is measured on a mass basis. The downhole pressure and temperature data will be used to perform the injectate density calculation. The volume of CO_2 injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected.

Density will be calculated using the correlation developed by Ouyang (2011). The correlation uses the temperature and pressure data collected to determine the CO_2 density. The density correlation is given by:

$$\rho = A_0 + A_1*P + A_2*P^2 + A_3*P^3 + A_4*P^4$$

Where ρ is the density, P is the pressure in psi, and A are coefficients determined by the equations:

$$A_i = b_{i0} + b_{i1}*T + b_{i2}*T^2 + b_{i3}*T^3 + b_{i4}*T^4$$

T is the temperature in degrees Celsius and the b coefficients are presented in Table E-3 and Table E-4 below.[1]

TABLE E-3. INJECTION VOLUME CALCULATION B COEFFICIENTS, PRESSURE < 3000 PSI

	bi0	bi1	bi2	bi3	bi4
i=0	-2.15E+05	1.17E+04	-2.30E+02	1.97E+00	-6.18E-03
i=1	4.76E+02	-2.62E+01	5.22E-01	-4.49E-03	1.42E-05
i=2	-3.71E-01	2.07E-02	-4.17E-04	3.62E-06	-1.16E-08
i=3	1.23E-04	-6.93E-06	1.41E-07	-1.23E-09	3.95E-12
i=4	-1.47E-08	8.34E-10	-1.70E-11	1.50E-13	-4.84E-16

TABLE E-4. INJECTION VOLUME CALCULATION B COEFFICIENTS, PRESSURE > 3000 PSI

	bi0	bi1	bi2	bi3	bi4
i=0	6.90E+02	2.73E+00	-2.25E-02	-4.65E-03	3.44E-05
i=1	2.21E-01	-6.55E-03	5.98E-05	2.27E-06	-1.89E-08
i=2	-5.12E-05	2.02E-06	-2.31E-08	-4.08E-10	3.89E-12
i=3	5.52E-09	-2.42E-10	3.12E-12	3.17E-14	-3.56E-16
i=4	-2.18E-13	1.01E-14	-1.41E-16	-8.96E-19	1.22E-20

The final volume basis will be calculated as follows:

Volume basis (m^3/hr) = Mass basis (kg/hr) / density (kg/m^3)

E.3.4 CONTINUOUS MONITORING OF ANNULAR PRESSURE

MC will use the procedures below to limit the potential for any unpermitted fluid movement into or out of the annulus:

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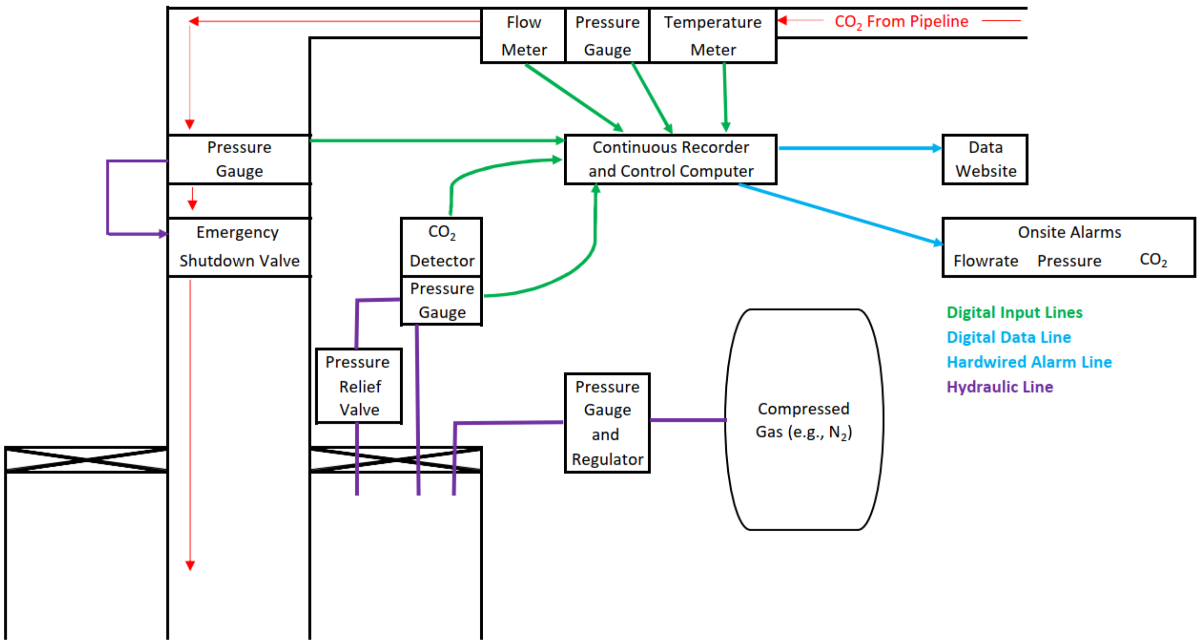
1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity of 1.26 and a density of 10.5 lbs/gal. The hydrostatic gradient is 0.546 psi/ft. The brine will contain a corrosion inhibitor, oxygen scavenger, and biocide.
2. The tubing/surface casing annulus pressure will be kept at a minimum of 500 psi during injection.
3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.
4. The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.
5. The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

Figure E-1 shows preliminary ground surface controls, including for annular space monitoring. The annular monitoring system will consis of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2.

Figure A.II-2 provides a schematic of above ground equipment for IW-A1, including annulus pressure regulation. The annulus pressure will be maintained and monitored by the MC control system gauges. The annulus head tank pressure will be controlled by pressure regulators–one set of regulators to maintain threshold pressure above 100 psi by adding compressed nitrogen or CO_2, and the other to relieve above the threshold pressure by venting gas off the annulus head tank. Any changes to the composition of annular fluid will be reported in the next report submitted to the permitting agency.

FIGURE E-1. PRELIMINARY INJECTION WELL SURFACE AND ANNULAR MONITORING SYSTEM GENERAL LAYOUT



If system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure and record hard copies of the data until communication is restored.

Average annular pressure and annulus tank fluid level will be recorded daily. The volume of fluid added or removed from the system will be recorded.

E.3.5 CASING-TUBING PRESSURE MONITORING

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. As detailed in the Emergency and Remedial Response Plan (Attachment H to this permit), significant changes in well mechanical integrity (casing-tubing pressure would be an example) will have a set of response actions.

Collection and recording of monitoring data will occur at the frequencies described in Table E-5.

TABLE E-5. SAMPLING AND RECORDING FREQUENCIES FOR CONTINUOUS MONITORING

Well Condition	Minimum sampling frequency: once every (1)(4)	Minimum recording frequency: once every (2)(4)
For continuous monitoring of the injection well when operating:	5 seconds	5 minutes (3)
For the injection well when shut-in:	4 hours	4 hours

Note 1: 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.
Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every minute.
Note 3: This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval.
Note 4: DTS sampling frequency is once every 10 seconds and recorded on an hourly basis.

E.4 CORROSION MONITORING

To meet the requirements of 40 CFR 146.90(c), MC will monitor well construction materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. Corrosion coupons will be mounted in the full CO_2 stream at a location downstream of the surface equipment and upstream of the injection wellhead.

After injection is authorized and based upon that date, this monitoring will occur on a quarterly interval at the following frequencies each year: 3 months, 6 months, 9 months, and 12 months. No coupon testing will occur during the Pre-Injection or PISC periods since the CO_2 stream will not be available during those times.

MC will monitor corrosion as described below.

E.4.1 SAMPLE DESCRIPTION

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table E-6 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see “Sample Handling and Monitoring” below).

TABLE E-6. LIST OF EQUIPMENT COUPON WITH MATERIAL OF CONSTRUCTION

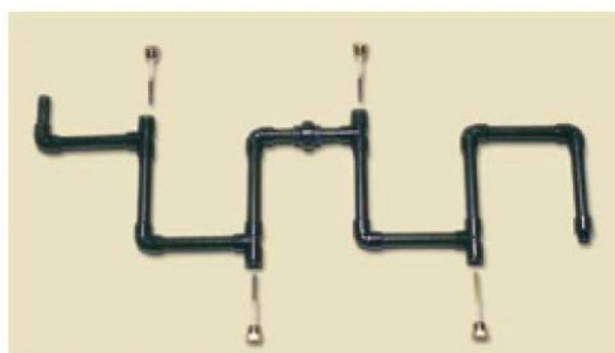
Equipment Coupon	Material of Construction
Pipeline	CS A106B
All Casing Strings	CR13
Injection Tubing	CR13
Wellhead	CR13
Packers	CR13

E.4.2 SAMPLE EXPOSURE

Each sample will be attached to an individual holder (Figure E-2A) and then inserted in a flow-through pipe arrangement (Figure E-2B). These example illustrations were taken from the ADM CCS#2 Class VI application. The corrosion monitoring system will be located downstream of all process compression and dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high-pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

FIGURE E-2A. COUPON HOLDER

FIGURE E-2B. FLOW-THROUGH PIPE ARRANGEMENT



E.4.3 SAMPLE HANDLING AND MONITORING

The coupons will be handled and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). The coupons will be photographed, visually inspected with a minimum of 10x power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gram).

E.5 ABOVE CONFINING ZONE MONITORING

MC will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

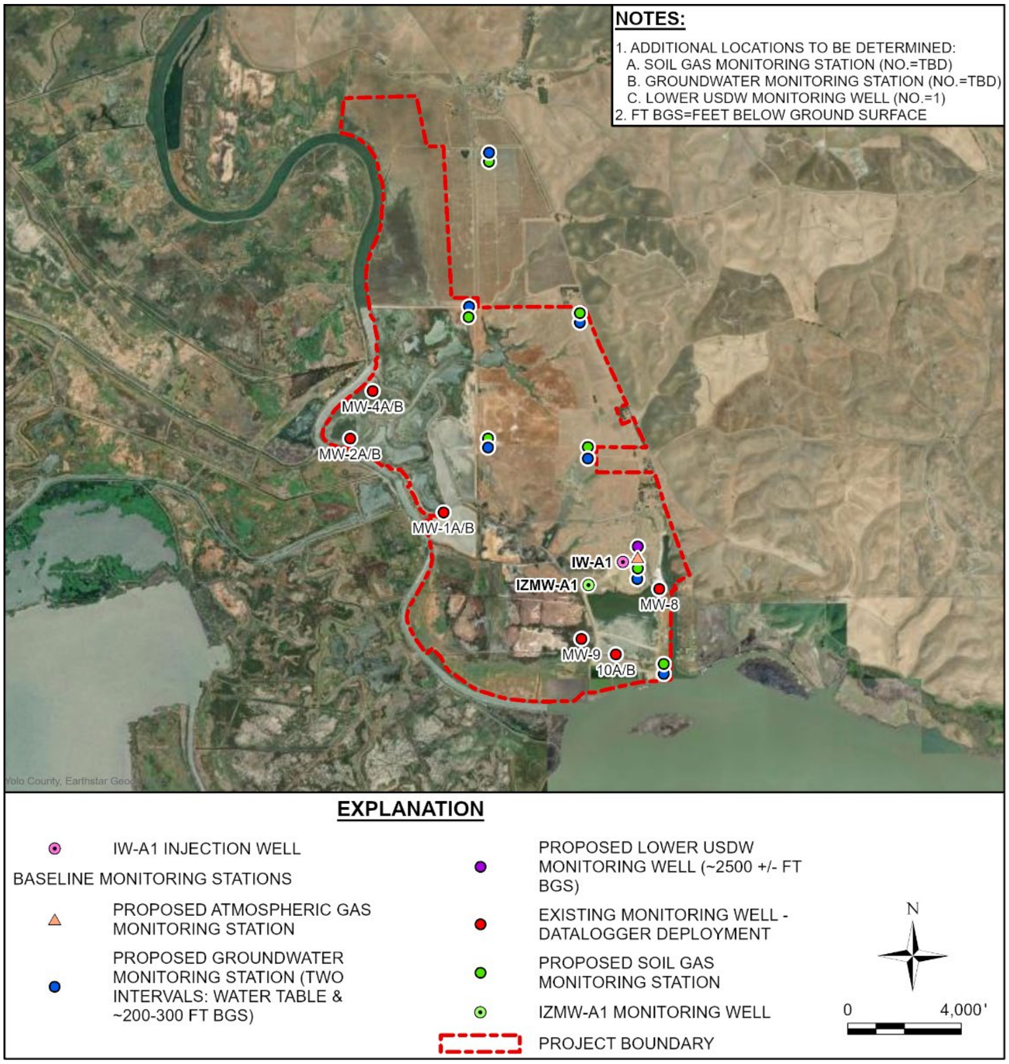
MC plans to install a network of seven (7) monitoring stations (MS-1 through MS-7) within and in the vicinity of IW-A1 and within the AoR as illustrated in Figure E-3. All of the monitoring stations will include monitoring wells screened within the following zones (both above the confining zone):

- Water-table/shallow alluvial aquifer (total depth ~25 to 30 ft below ground surface [bgs])
- Deep alluvial aquifer (total depth ~250 to 300 ft bgs)

Additionally, the monitoring station adjacent to IW-A1 will also include a deeper monitoring well intended to monitor the zone near the bottom of the lowermost USDW (Tehama Formation) at a depth pf approximately 2,000 ft bgs.

Associated with the Montezuma Wetlands operation that is co-located along the southwestern border of this property is a series of 12 existing monitoring wells (4 shallow 2-inch diameter well and 8 intermediate depth (i.e., between the shallow and deep aquifers noted above) 4-inch diameter wells.

FIGURE E-3. LOCATION OF SHALLOW GROUNDWATER MONITORING WELLS AND DEEP MONITORING WELLS



Groundwater quality will be continuously monitored for water level (pressure), temperature, conductivity, and salinity using downhole multi-parameter data loggers installed in each of the newly installed above confining zone monitoring wells. The existing 4-inch diameter monitoring wells will also be equipped with these downhole multi-parameter data loggers.

Groundwater quality data will be transmitted to MC (and its subcontractors) by telemetry for real-time remote monitoring. Data loggers are also installed at each of these monitoring stations for redundancy in case of a failure in the telemetry system. See Section E.I.2 of the QASP for more detail.

Geochemical monitoring and selected isotope analysis of groundwater above the confining zone will be accomplished by laboratory analysis of grab samples from each of the monitoring wells. Dedicated bladder pumps will be used to collect these samples from the newly installed shallow and deep alluvial aquifer monitoring well nests.

Table E-7 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone.

TABLE E-7. SUMMARY OF ABOVE CONFINING ZONE GROUNDWATER QUALITY AND GEOCHEMICAL MONITORING

Target Formations	Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
Water table (shallow/deep alluvial aquifer) & Tehama Formation [Lowermost USDW]	Groundwater Quality	MW-SA1 thru SA7, MW-DA1 thru DA7, MW-LU/TF1 (Existing 4-in diameter MWs CTD DLs only)	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Continuous
				Injection	Continuous
				PISC	Initial: Continuous Maintenance: Data Logger Only
Water table (shallow/deep alluvial aquifer) & Tehama Formation [Lowermost USDW]	Geochemical Monitoring	MW-SA1 thru SA7, MW-DA1 thru DA7, MW-LU/TF1	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Quarterly
				Injection	Year 1-2: Quarterly Year 3-5: Semi-annual Remainder: Annual
				PISC	Initial: Annual Maintenance: Every 5 years

The locations of monitoring stations MS-1 through MS-7 were selected to provide broad coverage across the property, areal extent of the AoR, and the MMA.

E.5.1 ANALYTICAL PARAMETERS

Table E-8 identifies the parameters to be monitored and the analytical methods MC will use.

Internal consistency of the geochemical results for each sample will be validated using the procedures given in Section E.I.2.5 of the QASP. Outlier data will be identified using the procedures given in Section E.I.2.5 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 potential brine or CO_2 leakage to USDW or the surface.

The analyte list in Table E-8 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.

TABLE E-8. SUMMARY OF ANALYTICAL AND FIELD PARAMETERS FOR GROUNDWATER SAMPLES

Target Formations	Analytes	Analytical Methods[1,2]
Water table (shallow/deep alluvial aquifer) & Tehama Formation [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[4] (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

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

Note 4: Pro-Oceanus - Solu Blu CO_2 sensor is proposed for use to measure dissolved CO_2 levels in the groundwater in the field using a flow through cell during well sampling events.

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.5.2 SAMPLING METHODS

Sampling methods are described in Section E.I.2.2 of the QASP.

E.5.3 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 of the QASP. Field quality control is described in Section E.I.2.5 of the QASP.

E.6 INTERNAL MECHANICAL INTEGRITY TESTING

An annulus pressure test (i.e., tubing-casing annulus pressure test) will be conducted on IW-A1 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 is the primary method to ensure internal mechanical integrity of IW-A1 during the Injection period, conforming to the requirements of 40 CFR 146.90(b). During the Injection period, MC will go beyond the minimum by conducting an annulus pressure test on IW-A1: 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.

There will be no internal MITs conducted on IW-A1 after the Initial PISC period of the project since the tubing and other internals will have been permanently removed at the end of this period.

A standard annulus pressure test procedure will be followed patterned off the procedure provided by the US EPA (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 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 approximately 110% above the anticipated maximum pressure for this system that will be designed to maintain a pressure of at least psi greater than that of the CO_2 injection system (*note: the actual number for this pressure is preliminary in nature and will be set after completion of stratigraphic well installation and final reservoir modeling analysis*). 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.

The data obtained from the standard annulus pressure test will be interpreted as follows:

1. If the annulus pressure changed by less than 3% of the test pressure (gain or loss) then the well has demonstrated internal mechanical integrity.
2. Validation of test results requires evaluation of the amount of liquid returned using the procedure published by US EPA (EPA 2008). Additional details and modifications to these plans may occur after completion of stratigraphic well installation, testing and completion of the final reservoir modeling.

E.7 EXTERNAL MECHANICAL INTEGRITY TESTING

MC will conduct at least one of the tests presented in Table E-9 during the injection phase to verify external mechanical integrity as required at 40 CFR 146.89(c) and 146.90. MITs will be performed annually, up to 45 days before the anniversary date of authorization of injection each year, or alternatively scheduled with the prior approval of the UIC Program Director.

TABLE E-9. MITS

Test Description	Location
Temperature Log	Along wellbore using DTS or wireline log
Noise Log	Wireline log or DAS
Oxygen Activation Log	Wireline log

E.7.1 TESTING LOCATION AND FREQUENCY

External MITs will be conducted on both IW-A1 and IZMW-A1. IW-A1 will initially be placed into service as an injection well, then will be re-completed and re-permitted as a monitoring well for the Maintenance PISC period. The frequency of testing for IW-A1 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. IZMW-A1 will serve as a monitoring well for its entire service life. The frequency of testing for IZMW-A1 will be at least once prior to placing the well into service, annual during Injection, annual during the Initial PISC period, and once every five years during the Maintenance PISC period.

E.7.2 TESTING DETAILS

Pass/fail results from external MITs conducted on IW-A1 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 IZMW-A1 will also be corroborated with analysis of data from the Corrosion Monitoring program.

E.7.3 DESCRIPTION OF MIT(S) THAT MAY BE EMPLOYED

Temperature Logging Using Wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures, will be employed for temperature logging:

The well should be in a state of injection for at least 6 hours prior to commencing operations in order to cool injection zones.

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a temperature survey from the base of the Upper Martinez Shale (or higher) to the deepest point reachable in the Anderson sandstone while injecting at a rate that allows for safe operations.
3. Stop injection, pull tool back to shallow depth, wait 1 hour.
4. Run a temperature survey over the same interval as step 2.
5. Pull tool back to shallow depth, wait 2 hours.
6. Run a temperature survey over the same interval as step 2.
7. Pull tool back to shallow depth, wait 2 hours.
8. Run a temperature survey over the same interval as step 2.
9. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the top-most section of the log, additional logging runs over a higher interval will be required to find the top of migration.
10. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 2.
11. Rig down the logging equipment.
12. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity (i.e., tubing leak or movement of fluid behind the casing). As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

Temperature Logging Using DTS Fiber Optic Line

IW-A1 will be equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the full length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.
2. During injection operation, record the temperature profile for 6 hours prior to shutting in well.
3. Stop injection and record the temperature profile for 6 hours.
4. Evaluate data to determine if additional cooling time is needed for interpretation.
5. Start injection and record the temperature profile for 6 hours.
6. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity (i.e., tubing leak or movement of fluid behind the casing). The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance, providing an advantage to wireline temperature logging.

Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from the lowermost USDW (Tehama Formation) to the deepest point reachable in the Anderson sandstone. Bottom hole pressure data near the packer will also be provided. Noise logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a noise survey from the from the base of the Upper Martinez Shale (or higher) to the deepest point reachable in the Anderson sandstone while injecting at a rate that allows for safe operations.
3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.
4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:
   - The base of the lowermost bleed-off zone above the injection interval.
   - The base of the lowermost USDW (Tehama).
6. Additional measurements may be made to pinpoint depths at which noise is produced.
7. Use a vertical scale of 1 or 2 inches per 100 feet.
8. Rig down the logging equipment.
9. Interpret the data as follows: Determine the base noise level in the well (dead well level). Identify departures from this level. An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations. Determine the extent of any movement; flow into or between USDWs indicates a lack of mechanical integrity; flow from the injection zone into or above the confining zone indicates a failure of containment.

Noise Logging Using DAS Fiber Optic Line

The injection well will also be equipped with a DTS/DAS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DAS line is used for real time noise monitoring and, like a conventional noise log, can be used for early detection of well noise changes that may indicate a loss of well mechanical integrity. The procedure for using the DAS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline noise profile will be established.
2. When DTS data is collected, also collect DAS noise levels.
3. Data interpretation involves identifying areas of higher noise and evaluating those areas compared to formation noise.

E.7.4 OXYGEN ACTIVATION (OA) LOGGING

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from the lowermost USDW (Tehama Formation) to the deepest point reachable in the Anderson sandstone. Bottom hole pressure data near the packer will also be provided. Oxygen Activation (OA) logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Conduct a baseline Gamma Ray Log and casing collar locator log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool.
3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13-3/8 inches.
4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.
5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.
6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.
7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.
8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.
9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.
10. If flow is indicated by the OA log at a location, move uphole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.
11. Interpret the data: Identification of differences in the activated water's measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected may indicate flow in the annulus or behind the casing. The flow velocity is determined by measuring the time that the activated water passes a detector.

E.8 PRESSURE FALL-OFF TESTING

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

Pressure fall-off testing will be performed:

- Prior to initiation of injection

- Approximately every 5-years during active injection; and
- At the end of the injection period.

MC will conduct pressure fall-off testing according to the procedures below.

E.8.1 PRESSURE FALL-OFF TEST PROCEDURE DETAILS

A pressure falloff test has a period of injection followed by a period of no-injection or shut-in. Prior to the falloff test, a uniform injection rate representing the average injection rate over the previous 90 days will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge, so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition, or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or less for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range).

E.9 CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

MC will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g). Table E-10, Table E-11, and Table E-12 present the direct and indirect methods that MC will use to monitor the position of the CO_2 plume and pressure front, including the activities, locations, and frequencies MC will employ.

TABLE E-10. PLUME MONITORING ACTIVITIES

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency[1-4]
Direct Plume Monitoring			
Anderson formation	Fluid sampling	IZMW-A1	Baseline; Year 1-3: Annual
Indirect Plume Monitoring			
Anderson formation	Pulse Neutron Logging/RST	VW#1	Baseline, Year 2, Year 4
		CCS#2	Baseline, Year 2, Year 4

Note 1: Baseline monitoring will be completed before injection is authorized.
Note 2: Annual monitoring will be performed up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.
Note 3: Logging surveys will take place up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

TABLE E-11. PRESSURE-FRONT MONITORING ACTIVITIES

Target Formation	Monitoring Activity	Monitoring Location(s)	Monitoring Zones	Frequency
Direct Pressure-Front Monitoring				
Anderson	Pressure / temperature monitoring	Injection Well	Surface, Reservoir and Selected Locations along the wellbore	Continuous
		Monitoring Well	Surface, Reservoir and Selected Locations along the wellbore	Continuous
	DTS/DSS/DAS	Injection Well	Surface, Reservoir and Selected Locations along the wellbore.	Continuous
		Monitoring Well	Surface, Reservoir and Selected Locations along the wellbore	Continuous

TABLE E-12. SUMMARY OF ANALYTICAL AND FIELD PARAMETERS FOR FLUID SAMPLING

Parameters	**Analytical Methods [1]**
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

E.10 INDIRECT GEOPHYSICAL MONITORING OF PRESSURE, PLUME, AND INDUCED SEISMICITY

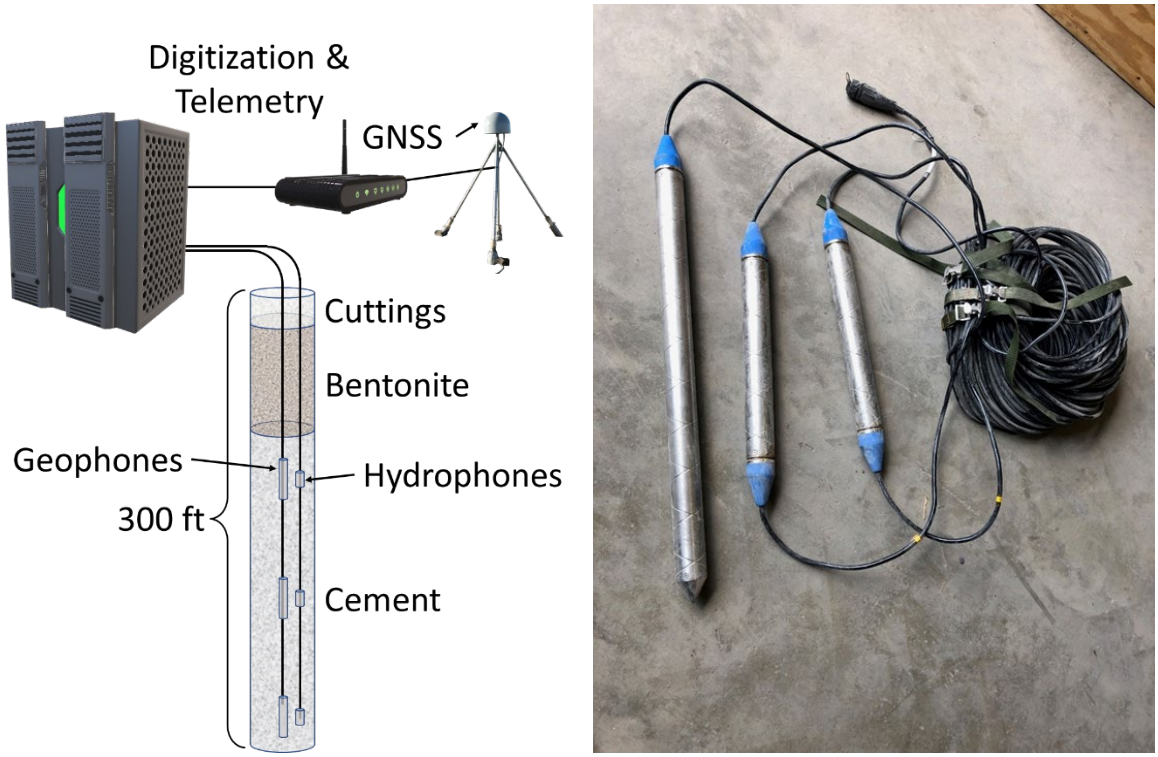
E.10.1 PLUME, PRESSURE, AND INDUCED SEISMICITY MONITORING USING SEISMIC METHODS

Seismicity (baseline and injection induced), CO_2 plume characteristics (pressure, saturation, etc.), and above-USDW changes will be monitored using an extensive toolbox of conventional seismic methods using both active and passive configurations, including conventional time-lapse 3D, continuous passive seismic event monitoring, time lapse 3D vertical seismic profiling (VSP).

Continuous Event Monitoring – Acquisition

Figure E-4 illustrates the part of the system that will be used to detect natural and induced seismicity near the site, and geodetic measurements using a Global Navigation Satellite System (GNSS) sensor. Boreholes (approximately 300 ft TD) will be drilled in and around the site in which multi-level geophones (3-component 4.5 Hz geophones) and hydrophones will be deployed. The geophones and hydrophones for each station will be permanently cemented in place, and the borehole space above the cement column will be filled with bentonite, and cuttings for the last 20’ to 30’ (this prevents noise from the surface contaminating the sensors).

FIGURE E-4. BOREHOLE AND GEOPHONE SYSTEM



As shown in Figure E-5, the digitization hardware includes a Sigma3 3-channel 24-bit delta-sigma digitizer, and a 5G Cradlepoint antenna with a Cradlepoint 5 GB MBA-3 router, powered by a 200 W solar panel with a charge controller for a 24-volt power supply (with battery backup). Figure E-6 shows boreholes (in yellow) that will be drilled close to the injection well and in a zone around the Kirby Hills fault to detect deep natural seismicity from the fault at depths of approximately 20 km, and injection induced seismicity, which should be confined to the reservoir interval at about 3.6 km. Sensors in these wells will be also used to augment other seismic surveys collected before and during injection.

FIGURE E-5. SOLAR PANEL WITH DIGITIZATION AND TELEMETRY HARDWARE

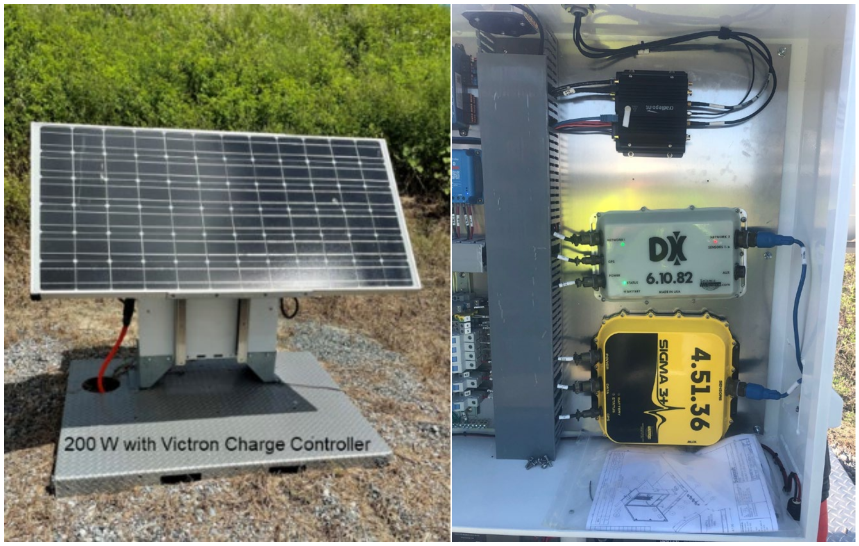
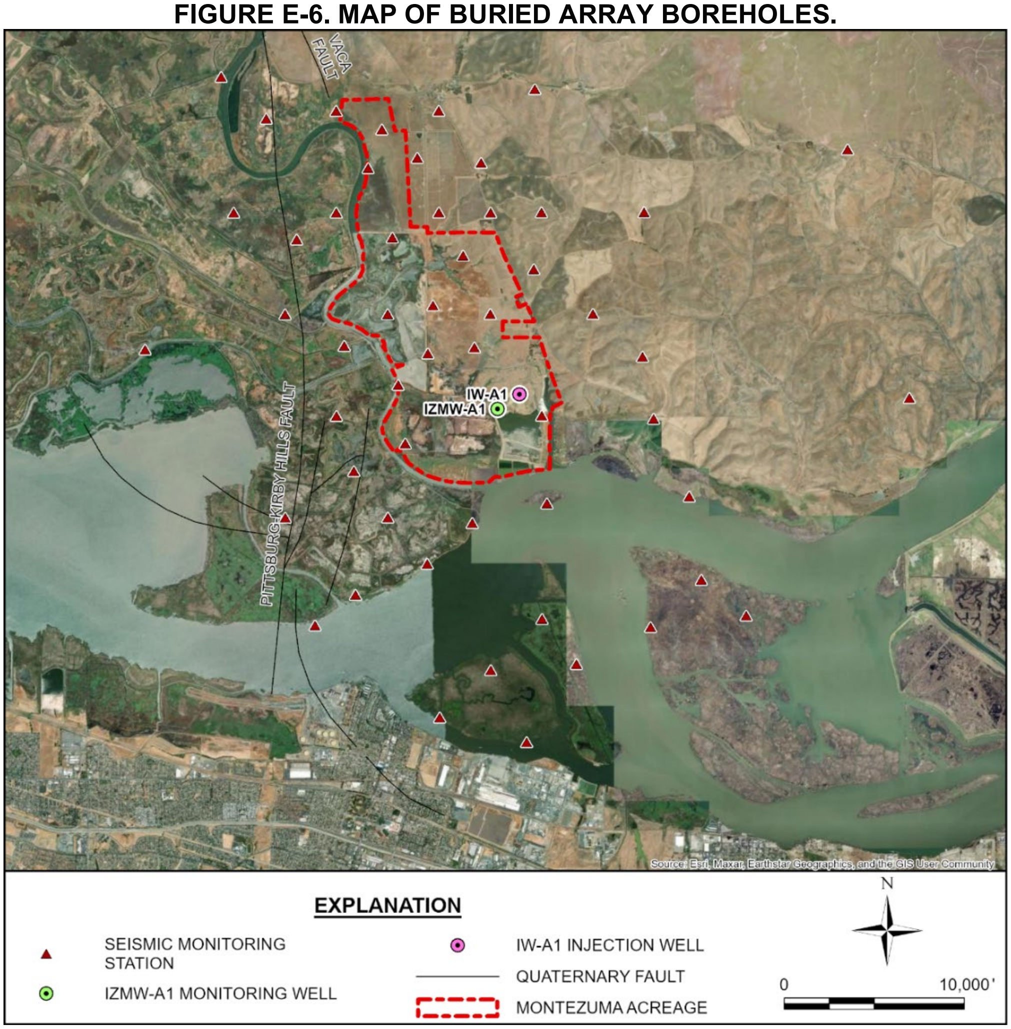
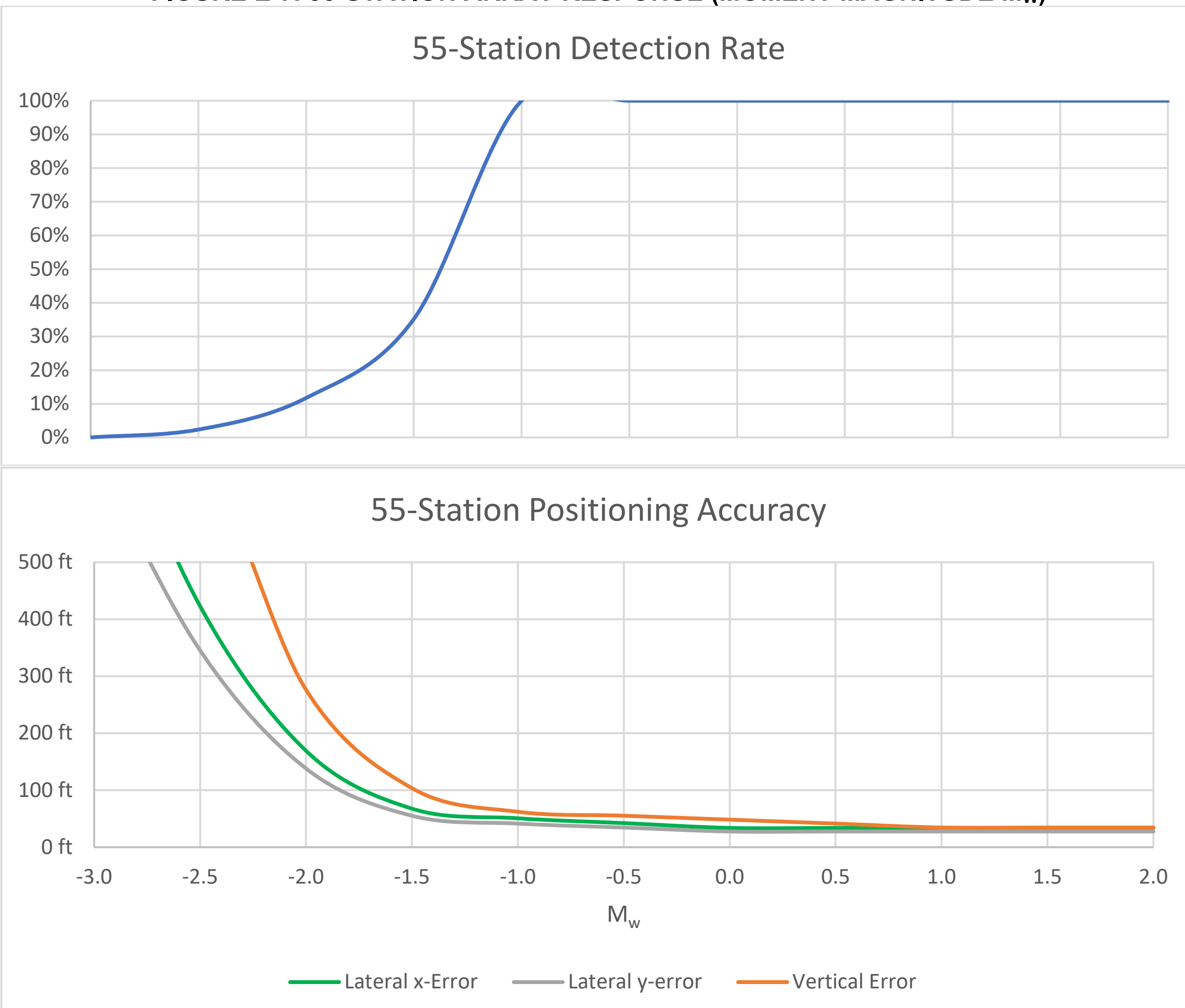


FIGURE E-6. MAP OF BURIED ARRAY BOREHOLES.



As shown in Figure E-7 below, preliminary modeling shows the array has a Magnitude of Completeness (M_c) of approximately $M_c = -1.5$ (i.e., 90% or more of seismic events $M_w = -1.5$ or higher will be detected and catalogued with a location accuracy of 50 to 75 ft).

FIGURE E-7. 55-STATION ARRAY RESPONSE (MOMENT MAGNITUDE M_W)



In addition to the BuriedArray, DAS fiber in the monitor and injection wells will be utilized as a seismic receiver to enhance the quality of induced seismicity event detection and to improve the image quality of the VSP and 3D seismic surveys. Modeling suggests the DAS array could improve the vertical accuracy of catalogued events in proximity to the monitor well by as much as 30%. DAS fiber installation and integrator are shown in Figure E-8 below.

FIGURE E-8. DAS FIBER INSTALLATION AND INTEGRATOR

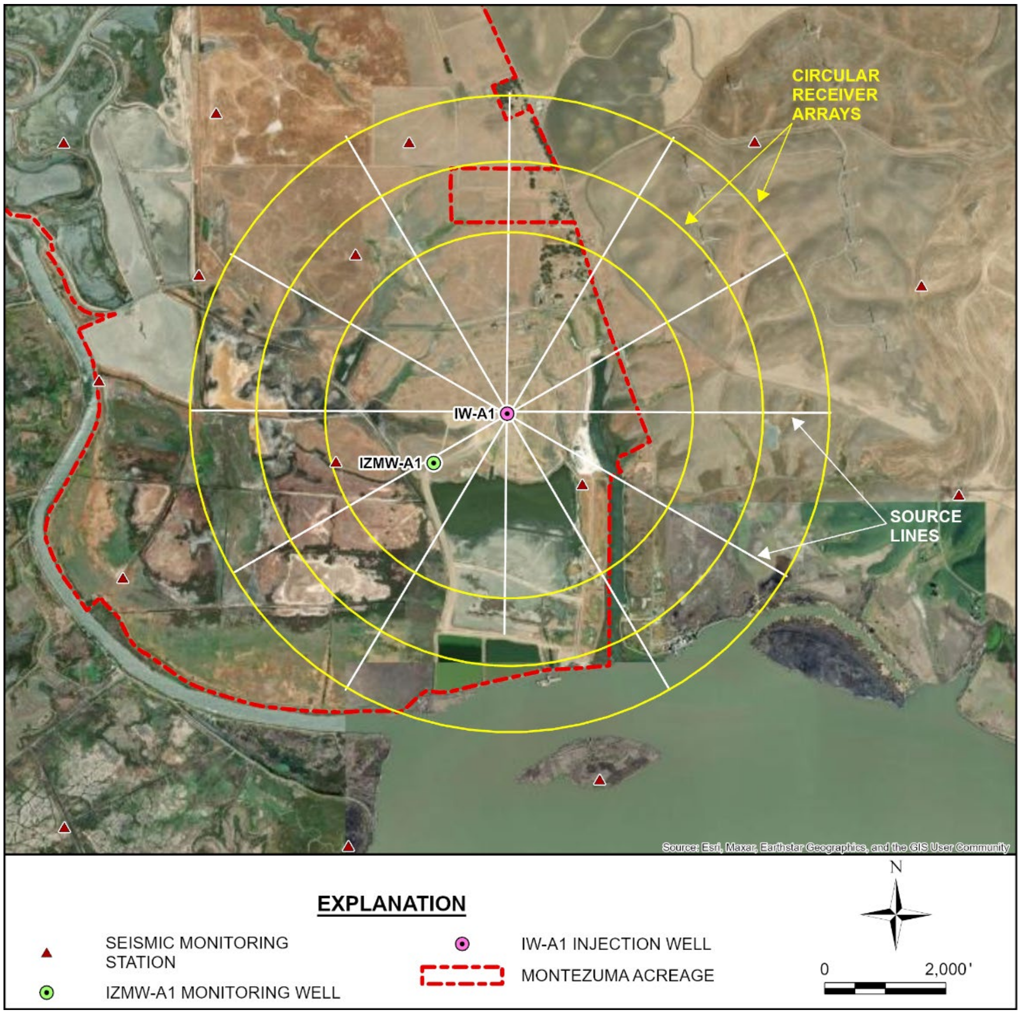
Continuous Event Monitoring – Processing and Interpretation

The monitoring stations will relay near real-time continuous seismic data to a cloud-based server. A daily report on the health of the array is maintained such that remedial action can be taken if the array should experience any station failures. Real-time processing involves the detection, location, and characterization of microseismic events accomplished with a PSET. Passive seismic event location via beamforming is a variation of Kirchhoff pre-stack depth migration, where the recorded seismic data are digitally backpropagated into a model of the earth. Points in time and space where energy focusing is observed are identified as potential event hypocenters and are refined and qualified as events using an analysis of the wavefield kinematics. The velocity and amplitude attenuation field is characterized by the VSP direct arrival data and then refined by near surface data from the BuriedArray and spatially variable velocity data provided by the 3D seismic data. Once an event has been located and qualified, several attributes can be computed from the recorded wavefield to characterize the quality of the detection, the magnitude, and focal mechanism of the underlying microseismic event.

Active Source 3D and VSP surveys

A baseline 3D survey, which will encompass the entire AoR, will be acquired prior to drilling the monitoring well to aid in site characterization and well locations. After the monitor well is completed, a 3D VSP will be acquired to provide parameters (velocity/attenuation, etc.) that aid in processing and interpretation of the baseline 3D survey, and that provide parameters for microseismic event locations.

FIGURE E-9. MONITOR 3D SURVEY LAYOUT



During the early stages of injection when the plume and pressure are confined to a region near the injection well, extensive seismic monitoring using repeat surveys will be performed. For the first few months, we plan to collect repeat surveys from time scales of minutes (passive seismic) to hours (VSP) to days (3D), to aid in understanding pressure front and early plume evolution. Most seismic monitoring studies in the past have been focused on very coarse snapshots (years). Our approach will provide much more granular information which will improve resolution, accuracy and allow other properties such as pressure diffusion to be characterized near the injection well. This will require the DAS system as well as a dedicated array of receivers deployed in a ring around the injection well, and multiple sources moving around the monitoring well location (Figure E-9).

E.10.2 INSAR MONITORING

As subsurface pressures increase as a result of CO_2 injection, millimetric scale surface deformation may be observed, which will reflect the morphology and evolution of the pressure front and can be detected and monitored using InSAR (Interferometric Synthetic Aperture Radar). InSAR has been successful utilized in several CO_2 injection monitoring programs, including at In Salah, Algeria; Decatur, Illinois; and Gorgon, Australia, among others. One of the advantages of InSAR over seismic methods is the fact that CO_2 saturation will not affect ground deformation whereas seismic techniques have difficulty in distinguishing pressure from saturation effects. Thus, combining the techniques will provide a means to separate the two effects. An idealized cylindrical reservoir and the following inputs can be used with an analytical solution to approximate surface displacement:

- Reservoir height: 100 – 400 m
- Reservoir depth: 3000 m
- Pressure Change (dP): 6800 kPa
- Bulk Modulus of reservoir (K): 15 GPa

Based on these inputs, ground displacement will be on the order of cm. This is well above the 1 mm resolving power of the InSAR satellites we will be using and thus displacement should be easily identifiable.

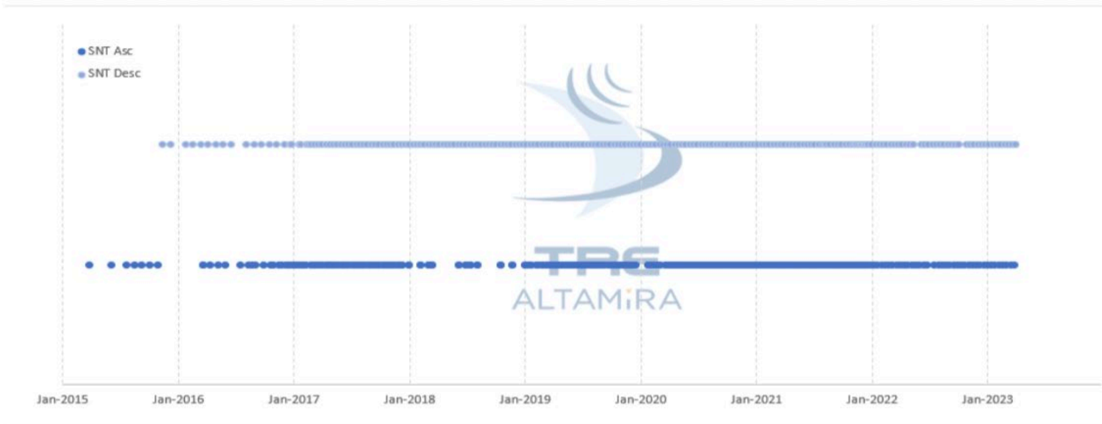
Presurvey Planning

A preliminary analysis well in advance of injection operations will be conducted using natural reflectors to inform the potential placement of artificial reflectors for monitoring (Figure E-10). It is likely that artificial reflectors will be needed, as the area has significant vegetation. To ensure calibrated point coverage, corner reflectors will be installed near each of the BuriedArray boreholes. 4.5” helical piles will be installed, on top of which the corner reflector will be mounted and oriented to the satellite orbits. Additionally, GNSS will be installed at selected boreholes, to provide calibration for the InSAR data. Collectively, this acquisition approach will provide robust spatial and temporal correlation for the different datasets.

FIGURE E-10. INSAR REFLECTORS

Figure E-10, above, shows 1D (left) and 2D (right) corner reflectors installed to augment natural reflector coverage. Preliminary analysis for presurvey planning will utilize data which has been acquired by the Sentinel-1 satellite constellation. This satellite has a pixel size (spatial resolution) of 65 x 15 ft, a wavelength of 2.2 inches and a nominal revisit frequency of 12 days, which is reduced to 6 days where multiple satellites are acquiring in the same configuration. This is the case over the AOI in the descending orbit from mid-2019 through to the beginning of 2022. Imagery collection for both tracks is ongoing. Data will be used from two historical image stacks from both an ascending and descending orbit, enabling 1D or 2D processing for historical analysis. Figure E-11 below illustrates the temporal density of the Sentinel data which will be included in the preliminary analysis.

FIGURE E-11. EXISTING IMAGERY DISTRIBUTION FOR SENTINEL-1 ARCHIVES OVER THE AOI



Processing of both data stacks will include data from 2016 through to the end of 2023. The workplan for the baseline analysis will be as follows:

1. The project team will download historical Sentinel-1 image archives from both ascending and descending orbits
2. Processing of each LOS dataset and decomposition into 2D (Vertical and East-West)
3. The project team performs quality checks
4. Data review meeting for project team
5. The project team develops a comprehensive report, which includes processing information, results, observations and future recommendations for corner reflector installation and monitoring

InSAR Monitoring

InSAR during- and post-injection monitoring will be performed using two different satellite constellations, the Sentinel-1 imagery which will also be used for the baseline, and a higher resolution, X-band constellation TerraSAR-X & PAZ which will acquire at a nominal revisit frequency of 4+7 days, with a pixel size of 10 x 10 ft and wavelength of 1.22 inches. Having both datasets for the monitoring program will enable cross-verification between datasets and provide the benefits of high-resolution/x-band (TSX/PAZ) and low-resolution/c-band (SNT) acquisitions. The c-band, Sentinel data will provide continuity with the baseline, and potentially better penetration of vegetation, due to the slightly longer wavelength. The higher resolution TSX/PAZ acquisitions will provide higher temporal sampling, as well as the ability to monitor corner reflectors located near wellheads, than GNSS stations or solar panels. It is likely that better and higher revisit frequency InSAR data will be available by the time monitoring operations begin and the data used will be modified accordingly. The workplan for monitoring activities will follow the same structure as the baseline analysis.

Ground and Structure Displacement Data

The InSAR data are vector data delivered in a shapefile format. The shapefile contains the location of the measurement points and has a database with details (i.e., attributes) about each measurement point (Table E-13).

The InSAR ground displacement database contains information on the time-series of displacement, the movement displacement rate, displacement rate standard deviation, acceleration, elevation, quality indexes and cumulative displacement values for each image date. The shapefile also includes the Reference Point.

TABLE E-13. LIST OF ATTRIBUTES COMMONLY DELIVERED WITHIN SHAPEFILES AND OTHER DATA FORMATS OF THE SQUEESAR RESULTS

Field	Description
CODE	Measurement Point (MP) identification code
HEIGHT	Topographic Elevation [m or ft] referred to WGS84 ellipsoid
H_STDEV	Height standard deviation [m or ft]
VEL	MP displacement rate. Positive values correspond to motion *toward the satellite;* negative values correspond to motion *away from the satellite* [mm/year or in/year]
V_STDEV	Displacement rate standard deviation [mm/year or in/year]
ACC	Acceleration [mm/year^2 or in/year^2]
A_STDEV	Acceleration standard deviation [mm/year^2 or in/year^2]
SEASON_AMP	Average seasonal amplitude, if applicable [mm or in]
COHERENCE	Quality index varying between 0 and 1.
EFF_AREA	This parameter represents the effective extension of the area [m^2 or ft^2] covered by Distributed Scatterers (DS). For Permanent Scatterers (PS), its value is set to 0
Dyyyymmdd	Fields containing the displacement values of successive acquisitions relative to the first acquisition available. Displacement values are expressed in [mm or in]

As previously noted, the baseline analysis will include a recommendation for the installation of a network of corner reflectors. The Monitoring deliverables will include calibration to the GNSS stations located adjacent to the selected corner reflectors.

E.11 SOIL GAS MONITORING [PROJECT-SPECIFIC TESTING AND MONITORING]

MC 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. Therefore, MC will implement a soil gas monitoring program to identify and quantify potential CO_2 leakage to the surface across the AoR and MMA as part of its risk mitigation strategy.

E.11.1 MONITORING LOCATIONS AND FREQUENCY

MC will install a network of 7 monitoring stations (MS-1 through MS-7) within and in the vicinity of the AoR and MMA as illustrated previously in Figure E-3. Each monitoring station will include a CO_2 gas sensor for measuring CO_2 concentrations in the upper vadose zone at a depth of approximately 5 to 7 ft bgs (SCSW-1 through SCSW-7), sampling vapor points to obtain soil gas grab samples in the upper vadose zone (SGP-1S through SGP-7S), and a set of 16 pre-installed soil collars at each station to simplify dynamic closed chamber (efflux) measurements at the surface.

Soil gas CO_2 concentrations will be continuously monitored by CO_2 sensors equipped with data loggers placed in the upper vadose zone. The data are transmitted during Pre-Injection, Injection, and Initial PISC periods to MC (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 vadose zone 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-14 shows the planned monitoring locations and frequencies for soil gas monitoring.

TABLE E-14. 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 to SCSW-7	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	SGP-1 to SGP-7	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Quarterly
			Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annually
			PISC	Initial: Annually Maintenance: Every 5 years
CO_2 Efflux Measurements at Each Station	MS-1 to MS-7	Grid of single point measurements within AoR/MMA and vicinity	Pre-Injection	Quarterly
			Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annually
			PISC	Initial: Annually Maintenance: Every 5 years

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

E.11.2 ANALYTICAL PARAMETERS

Table E-15 lists the analytes and analytical methods used for laboratory analysis of soil gas grab samples from the upper and lower vadose zones.

TABLE E-15. 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 - GM500 or equivalent) - dual wavelength infrared cell with reference channel
Carbon Dioxide - field	Field meter (Landtec - GM500 or equivalent) - dual wavelength infrared cell with reference channel
Oxygen - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell
Carbon Monoxide - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell
Hydrogen Sulfide - field	Field meter (Landtec - GM500 or equivalent) - internal electrochemical cell

E.11.3 SAMPLING METHODS

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

E.11.4 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 of the QASP. Field quality control is described in Section E.I.2.5 of the QASP.

E.12 SURFACE AIR MONITORING [PROJECT-SPECIFIC TESTING AND MONITORING]

MC 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. MC will implement an Inspection and Leak Detection Plan to identify and quantify CO_2 leakage to the atmosphere at the wellhead as part of its risk mitigation strategy.

Table E-16 shows the planned monitoring location and frequencies for the surface air (atmosphere) monitoring program. The plan consists of two components: (a) A CO_2 sensor installed near IW-A1 wellhead, with telemetry to provide MC with real time monitoring data and a data logger for redundancy, and (b) Periodic inspections of the above ground project equipment using a field meter to detect potential CO_2 leaks.

TABLE E-16. MONITORING LOCATIONS AND FREQUENCIES FOR SURFACE AIR (ATMOSPHERE) MONITORING

Monitoring Activity	Monitoring Locations	Spatial Coverage	Project Period	Frequency
CO_2 Concentration	near IW-A1 Wellhead	Single Point Measurement	Pre-Injection	Continuous(1)
			Injection	Continuous(1)
			PISC	Initial: Continuous(1) Maintenance: Continuous(1) (data logger only)
Field Measurements at Potential Leak Sources	IW-A1 Wellhead & pipeline on Montezuma property	Linear, multi-point Measurements	Pre-Injection	Quarterly
			Injection	Year 1-2: Quarterly Year 3-5: Semi-annually Remainder: Annually
			PISC	Initial: Annually Maintenance: Every 5 years

Note 1: Continuous for CO_2 concentrations is defined as measurements taken at 30-minute intervals, with a 6-hour averaged reading recorded

E.12.2 ANALYTICAL PARAMETERS

Table E-17 lists the analytes and analytical methods used for laboratory analysis of air grab samples from the surface air (atmosphere) adjacent to the injection wellhead.

TABLE E-17. SUMMARY OF ANALYTICAL PARAMETERS FOR SURFACE AIR MONITORING

Analyte	Analytical Method
Methane - field	Field meter (Landtec - GM500 or equivalent) dual wavelength infrared cell with reference channel
Carbon Dioxide - field	Field meter (Landtec - GM500 or equivalent) dual wavelength infrared cell with reference channel
Oxygen - field	Field meter (Landtec - GM500 or equivalent) internal electrochemical cell
Carbon Monoxide -field	Field meter (Landtec - GM500 or equivalent) internal electrochemical cell
Hydrogen Sulfide - field	Field meter (Landtec - GM500 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 of the QASP. Field quality control is described in Section E.I.2.5 of the QASP.

E.13. REFERENCES

ASTM, 2011, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens. G1-03.

EPA 2008, Attachment 1- Standard Annulus Pressure Test (SAPT), in Determination of the Mechanical Integrity of Injection Wells, US EPA Region 5 – UIC Branch Regional Guidance #5, Revised February, 2008. Available at: https://www.epa.gov/sites/default/files/2015-09/documents/r5-deepwell-guidance5-determation-mechanical-integrity-200802.pdf

Ouyang 2011. New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations. The Open Petroleum Engineering Journal, 2011, 4, 13-21.

APPENDIX

Quality Assurance and Surveillance Plan.