ATTACHMENTS

This Part includes, but is not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, as required by 40 CFR Parts 144 and 146. The Permittee must comply with these conditions as they are approved by the Director and incorporated into this Permit.

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ATTACHMENT A: SUMMARY OF OPERATING REQUIREMENTS

Facility Information

Facility name: Front Range Storage Complex

Well Name: Front Range 1-1

Well location: Weld County, Colorado
Surface Township, Range, Section: T6N, R67W, Sec 26
Bottomhole Township, Range, Section: T6N, R67W, Sec 35
Surface Latitude: 40.454962 Longitude: -104.859761
Bottomhole Latitude: 40.449494 Longitude: -104.852200

1.0 Operational Limits - Table 1 below contains permit conditions related to injection well operation. The Permittee must comply with the limits as indicated.

Table 1: Injection Well Operating Conditions, Parameters, and Limits

PARAMETER/CONDITION*	LIMITATION	UNIT
Downhole Maximum Allowable Injection Pressure at the Lyons Sandstone	4,640	psi
Minimum Annulus Pressure at all times	100	psi
Minimum Annulus Pressure above Tubing Differential (during injection)	100	psi
Carbon Dioxide Purity (minimum)	99	percent volume
Maximum Injection Rate	127,800	metric tons/year
Maximum cumulative mass of injected CO_2	1,540,000	metric tons

*See Attachment C, Table 2 Devices, location and frequencies for monitoring location.

Permittee is required by 40 CFR 146.89 to install and calibrate continuous recording devices (pressure, rate, temperature as applicable). Permittee must configure alarm and automatic shutoff/emergency shutdown (ESD) setpoints and logic with sufficient margin to prevent exceeding the downhole MAIP. The emergency shutdown points are listed in Table 2.

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Table 2: Operational emergency shut down set points

ALARM TYPE		SET POINT	UNIT
Downhole Maximum Injection Pressure at the Lyons Sandstone	Shutdown point: At least 95% of downhole maximum allowable injection pressure	4,408	psi
Annulus Pressure (during injection)	Shutdown point: Minimum	100	psi
	Shutdown point: Less than minimum allowable annulus over tubing differential	100	psi

<u>**Downhole Maximum Allowable Injection Pressure**</u>

To meet EPA requirements at 40 CFR 146.88(a), the downhole maximum allowable injection pressure (MAIP) for the Front Range 1-1 well is 90% of the fracture pressure of the Lyons Sandstone injection zone, measured using a downhole pressure gauge placed within 20 ft. of the top perforation of the Front Range 1-1 well. The fracture gradient of the Lyons Sandstone was calculated as 0.58 psi/ft based on the fracture propagation pressure determined by a step rate test performed at the Front Range 1-1, and the corresponding fracture pressure of the Lyons Sandstone at the depth of the top perforation in the Front Range 1-1 well (8,889 ft. true vertical depth) is 5,155 psi. The initial downhole MAIP for this permit is therefore set to 90% of 5,155 psi, or 4,640 psi. If the downhole pressure gauge is placed at a depth other than 8,889 ft., the downhole MAIP must be recalculated as:

$$MAIP = FG * D \text{, where}$$

MAIP is the downhole maximum allowable injection pressure (psi)

FG is the fracture gradient of the Lyons Sandstone (psi/ft), and

D is the true vertical depth of the gauge used to measure the downhole pressure (ft)

The downhole MAIP may be updated throughout the life of the well when testing or monitoring data indicates the formation fracture pressure differs from the current value. The recalculated downhole MAIP becomes effective and enforceable upon written correspondence from the Director. A permit modification is needed to implement a change to the MAIP.

1.1 <u>Injection Zone</u>

Injection must only occur into the authorized injection zone listed in the table below.

Formation Name	Top (ft. TVD)	Bottom (ft. TVD)
Lyons Sandstone Formation	8,876	8,958

(TVD, true vertical depth)

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1.2 Injection Fluid Limitation

Injected fluids are limited to CO_2 produced by the Front Range Energy, LLC ethanol production facility. As specified in Table 1 above, this injectate must consist of at least 99 percent by volume carbon dioxide. Written approval must be obtained from the Director prior to injection of any other fluids or source of CO_2., and any such change will result in a permit modification in accordance with 40 CFR 144.39 and 144.41.

2.0 Startup Procedures

The procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates must be gradually increased to the planned average rate over a period of six (6) days.

The procedures detailed below describe the requirements to initiate injection and conduct startup-specific monitoring of the injection well.

The multistage (injection rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup must follow Attachment C (Testing and Monitoring Plan) of this Permit.

This procedure can be performed using the existing surface and downhole pressure and temperature gauges in the injection well.

(a) During the startup period, the Permittee must submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the Permittee may be required to schedule a daily conference call to discuss this information.

(b) A series of successively higher injection rates must be applied, as shown in Table 3 below. The elapsed time and pressure values must be read and recorded for each rate and timestep.

(c) The planned injection rates are shown in Table 3.

Table 3: Planned Injection Rates During Startup

Rate (metric tons per day)	Duration (hours)	Percent of Average Daily Injection Rate
144	24	40
180	24	50
216	24	60
252	24	70
288	24	80
324	24	90

(d) The injection rates must be measured and recorded.

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(e) Surface and downhole pressures and temperatures must be measured and recorded.

(f) During the startup period, a graph of injection rates and their corresponding stabilized pressure values must be reviewed for evidence of anomalous pressure behavior and presented to the Director.

(g) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be required by the Director to characterize the anomaly and determine whether formation fracturing is indicated. If fracturing is identified, the Permittee must cease injection and follow the steps below:

(i) Measure the instantaneous shut-in pressure (ISIP).

(ii) Notify the Director within 24 hours of the determination.

(iii) Consult with the Director before initiating any further injection.

3.0 Operations After Startup

(a) Automatic alarms and automatic shutoff systems must be installed and maintained. Successful function of the alarm system and shutoff system must be demonstrated prior to injection and once annually thereafter.

(b) At all times, pressure must be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug must be installed that can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well.

(c) The Permittee must cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

1.0 Introduction

Pursuant to 40 CFR 146.84, this attachment includes the Area of Review (AoR) and Corrective Action Plan for wells that require corrective action. As a condition of this Permit and in accordance with the EPA's regulations set forth at 40 CFR 146.84, the Permittee must maintain, implement, and comply with an approved plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action on all wells in the AoR needing corrective action as determined by the Director.

1.1 Injection Zone, Confining Zones, and Lowermost Underground Sources of Drinking Water

The Lyons Sandstone interval shown in Table 1 is the allowable injection zone. The upper confining zone consists of the Lykins Formation with primary confinement provided by the Opeche Shale and Blaine Evaporite Members, which comprise the lower part of the formation. The Lower Satanka (Owl Canyon) Formation is the underlying confining unit beneath the Lyons Sandstone. The lowermost underground source of drinking water (USDW) was identified as the Ingleside Formation, which is below the Lyons injection zone. The lowermost USDW above the Lyons injection zone is the Entrada Sandstone. In accordance with Section E.1 of this Permit, the Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity for the Front Range 1-1 injection well and associated monitoring wells in a manner that allows the movement of a fluid containing any contaminant into USDWs.

Table 1: Summary of Injection Zone, Confining Zones, and Lowermost Underground Sources of Drinking Water (USDWs) at the Front Range 1-1 well (TVD, true vertical depth; MD, measured depth; *, projection from Front Range 2-1; NA, not applicable).

Formation	Description	Top (ft TVD)	Bottom (ft TVD)	Top (ft MD)	Bottom (ft MD)	Total Dissolved Solids (mg/L)
Entrada Sandstone	USDW	8,175	8,268	8,870	8,966	8,376
Lykins Formation (Blaine and Opeche Members)	Upper confining zone	8,792	8,876	9,494	9,524	NA
Lyons Sandstone	Injection zone	8,876	8,958	9,579	9,660	34,076
Lower Satanka (Owl Canyon) Formation	Lower confining zone	8,958	NA	9,660	NA	NA
Ingleside Formation	USDW	9,189*	9,737*	NA	NA	3,388

1.2 AoR Delineation

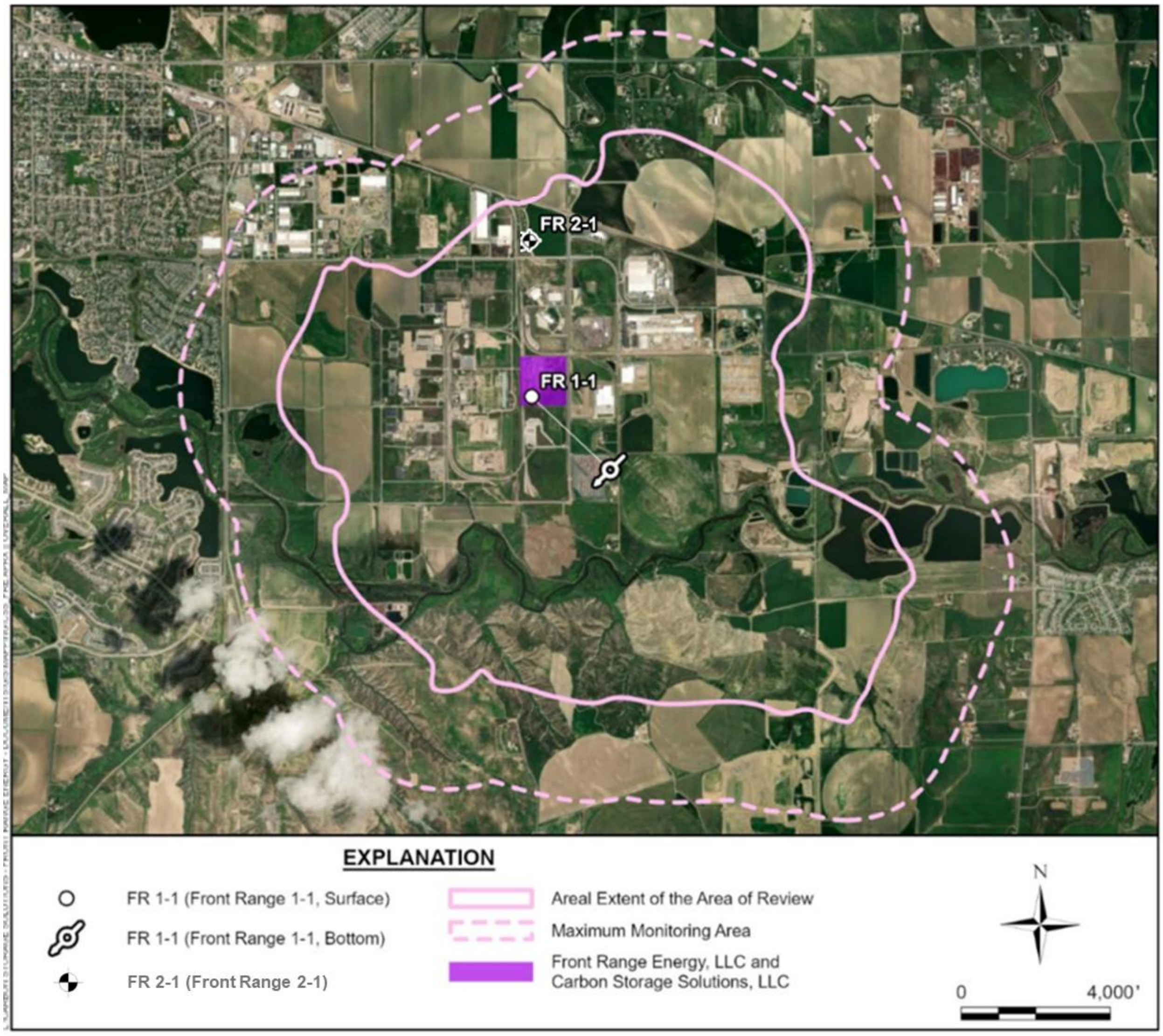
The AoR for the Front Range 1-1 well is shown in Figure 1. The AoR was delineated by using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide (CO_2) stream and is based on available site characterization data prior to receiving authorization to inject. The AoR has an area of about 6.4 square miles surrounding the bottomhole location of the Front Range 1-1. The AoR was determined as the union of the maximum extent of the simulated pressure front and the CO_2 plume, where the pressure front is defined by the critical pressure (3,865 psi) needed to move fluids from the injection zone into the Entrada USDW and the plume extent is defined by where the CO_2 concentration is greater than 1%. The critical pressure was calculated by using equation 1 of EPA, 2013 (Guidance 816-R-13-005):

$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i),$$

where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone.

Because the simulated maximum extent of the CO_2 plume exceeded the maximum extent of the pressure front, the AoR effectively is delineated by the maximum CO_2 plume extent, which occurs in year 32 (20 years after injection ceases). Computational modeling predicts the CO_2 plume will reach the Front Range 2-1 deep-zone monitoring well between years 5 and 8 and that the pressure front does not extend to this well at any time during the life of the project.

Figure 1: Area of review for the Front Range 1-1 well, delineated by using computational modeling based on available site characterization data. Location of Front Range 2-1 monitoring well is shown in the AoR.



1.3 Corrective Action Plan

Other than the Front Range 1-1 injection well, the only current penetration of the confining zones within the AoR is the Front Range 2-1 deep-zone monitoring well. This well has been properly constructed to Class VI standards to prevent movement of CO_2 or formation fluids out of the injection zone and must be monitored throughout the life of the well. No other artificial penetrations of the confining zones were identified within the AoR. Therefore, no corrective action is required.

1.4 AoR Reevaluation

The Permittee must reevaluate the AoR at a minimum frequency not to exceed every five years from the commencement of injection activities throughout the injection and post-injection site care periods, or more frequently when monitoring and operational conditions warrant. Activities to be performed during reevaluation must include the following:

(A) Review data collected as required by Attachment C (Testing and Monitoring Plan) and Attachment E (Post-Injection Site Care and Site Closure Plan) of this Permit since the previous AoR evaluation. Specifically:

(1) Review temperature, pressure, and pulsed neutron log data collected at the Front Range 1-1 and Front Range 2-1 wells for the Lyons Sandstone injection zone, the Entrada Sandstone USDW, and the Ingleside Formation USDW.

(2) Review operating data, including injection rates, volumes, and pressures, and the composition of the CO_2 stream.

(3) Review groundwater and dissolved gas chemistry data collected at the Front Range 2-1 wells for the Lyons Sandstone injection zone, the Entrada Sandstone USDW, and the Ingleside Formation USDW.

(4) Review groundwater and dissolved gas chemistry data collected from shallow monitoring wells completed in near-surface aquifers.

(5) Review soil gas data collected at soil gas monitoring stations.

(6) Review results of vertical seismic profiles.

(7) Identify all wells that fall within the AoR. Evaluate the status and records of wells that were not previously evaluated and provide a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion.

(8) Perform corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with CO_2.

(B) Compare data to the current AoR delineation

(1) If the monitoring and operating data indicate subsurface and operating conditions are consistent with inputs used in the current AoR delineation model, the pressure front and CO_2 plume are moving as predicted or are smaller than predicted, and there is no evidence of CO_2 or fluid movement into USDWs, then no amendment to the AoR is required. The Permittee must submit a report to the Director within 90 days of the reevaluation that demonstrates, based on monitoring data and modeling results, that no amendment to the AoR and corrective action plan is needed.

(2) If there is evidence that the pressure front or CO_2 plume may extend beyond the current AoR, or there is evidence of CO_2 or fluid movement into USDWs, the AoR must be delineated in the manner specified in 40 CFR 146.84(c). Steps to delineate the AoR include the following:

(a) Revise the site conceptual model based on the new monitoring data.

(b) Use computational modeling to simulate the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases or until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present.

(c) Calibrate the computational model to minimize the differences between monitoring data and model simulations.

(d) Determine which wells in the newly delineated AoR are plugged in a manner that prevents movement of CO_2 or other fluids that may endanger USDWs.

(e) Submit a report to the Director documenting the AoR reevaluation process, data evaluated, computational modeling results, the revised AoR, any corrective actions determined to be necessary, and status of corrective action or a schedule for any corrective actions to be performed. The report must be submitted to the Director within 90 days of the reevaluation and include maps that highlight similarities and differences between the current AoR delineation and previous AoR delineations.

(f) Within 90 days of the reevaluation, update the AoR and Corrective Action Plan to reflect the revised AoR, along with a description of how site access will be guaranteed for any needed corrective action, and submit to the Director. Any amendments to the AoR and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

(g) Update the Testing and Monitoring Plan, Post-Injection Site Care and Site Closure Plan, Emergency and Response Plan, and demonstration of financial responsibility to account for the revised AoR as required by the Director.

(C) The Permittee must retain all modeling inputs and data used to support the AoR reevaluation for 10 years.

(D) Conditions Warranting AoR Reevaluation Prior to Scheduled Reevaluation

If monitoring and operational conditions indicate any of the following circumstances, the Permittee must reevaluate the AoR in accordance with (A) and (B) above::

(1) Significant changes in site operations that may alter model predictions and the AoR delineation. Specifically, an unscheduled AoR reevaluation may be required when the limits shown in Table 1 of Attachment A of this Permit are exceeded for injection zone pressure, injection rate, or cumulative mass of injected CO_2 if those exceedances could result in the pressure front or CO_2 plume reaching the current AoR boundary prior to the next scheduled AoR reevaluation.

(2) Monitoring data indicate the pressure front or CO_2 plume may reach the current AoR boundary prior to the next scheduled AoR reevaluation.

(3) New site characterization data are acquired that indicate the pressure front or CO_2 plume may reach the current AoR boundary prior to the next

schedule AoR reevaluation.

(4) Monitoring data indicate that CO_2 or other fluids have moved into a USDW, unless the movement is related to well integrity.

ATTACHMENT C: TESTING AND MONITORING PLAN

This Testing and Monitoring Plan describes the requirements for the Permittee pursuant to 40 CFR 146.90 and per Section N of this Permit. The monitoring data must be used to demonstrate that the well is operating as planned, the CO_2 plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs). The Permittee must also use monitoring data to evaluate the computational model to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration. The Permittee must review the Testing and Monitoring Plan at least once every five years. Based on this review, the Permittee must submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan in Attachment F of this permit.

1.0 Carbon Dioxide Stream Analysis

The Permittee must analyze the CO_2 stream during the operation period with sufficient frequency to yield data representative of its chemical and physical characteristics consistent with 40 CFR 146.90(a). The Permittee must sample and analyze the carbon dioxide stream as presented below.

1.5 Sampling Location and Frequency

The Permittee must collect samples of the CO_2 stream at quarterly intervals. CO_2 stream will be obtained to analyze the constituents present in the injection stream. Samples of the CO_2 stream must be collected at a location in the system where the fluid is representative of the fluid injected (i.e., between the compression system and the Front Range 1-1 (FR 1-1) well), using a sampling port in the flowline.

1.6 Analytical Parameters

The CO_2 must be analyzed for the constituents identified in Table 1, which lists the specifications of the injected CO_2 stream. This analysis will ensure that the CO_2 stream composition entering the injection well is consistent with the required composition of 99% carbon dioxide.

Table 1: CO_2 stream analytical methods for constituent composition.

Parameter	Frequency of Analysis	Analytical Method
Isotopes: $\delta^{13}C$ of DIC	Every 5 years	Isotope ratio mass spectrometry
CO_2 Purity	Quarterly	ISBT 2.0
Water (H2O)		ISBT 3.0
Hydrogen Sulfide		ISBT 14.0

Total Sulfur		ISBT 13.0
Total Hydrocarbons as Methane		ISBT 10.0
Total Non-Methane Hydrocarbon (TNMHC)		ISBT 10.1
Carbon Monoxide (CO)		ISBT 5.0
Ammonia (NH_3)		ISBT 6.0
Oxides of Nitrogen (NO_x)		ISBT 7.0
Nitrogen Dioxide (NO_2)		ISBT 7.1
Nitric Oxide (NO)		ISBT 7.2
<u>Non-Condensable Gases:</u> Nitrogen (N_2) Oxygen (O_2) Argon (Ar) Hydrogen (H_2) Helium (He)		ISBT 4.0

2.0 Continuous Recording of Operational Parameters

The Permittee must install and use continuous recording devices at the FR 1-1 to monitor wellhead and downhole formation injection pressure, mass flow rate, and volume (calculated); pressure on the annulus between the tubing and the long string casing; annulus fluid level; CO_2 stream temperature, and downhole formation temperature. (40 CFR 146.90(b), 146.88(e)(1), and 146.89(b)).

2.1 Monitoring Location and Frequency

Injection operations must be continuously monitored and controlled by the Permittee utilizing a process control system. The system must continuously monitor, control, record, and alarm for critical system parameters of pressure, temperature, and injection flow rate. The system must initiate a shutdown if specified control parameters deviate from the intended operating range and must allow for remote shutdown under emergency conditions. Trend analysis must be used in evaluating the performance (e.g., drift) of the instruments, indicating the need for maintenance or recalibration. Monitoring methods and frequencies are summarized in Table 2.

Table 2: Devices, locations, and frequencies for monitoring at Front Range 1-1

Parameter	Device(s)	Location	Sampling Frequency	Recording Frequency	Reporting Frequency	Reporting Parameter
Injection Pressure at Wellhead (psi)	Pressure Gauge	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum

Injection Rate (bbl/day)	Orifice Meter	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Injection Volume (calculated) (bbl)	Volumetric Flow meter & computer	CO_2 Delivery Flowline	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Cumulative Injection Volume (bbl)	Volumetric Flow meter & Flow computer	CO_2 Delivery Flowline	Continuous (min every 10 sec)	Monthly	Semi-Annual	Lifetime Cumulative
Annular Pressures (psi)	Pressure Gauges	Wellhead and bottom hole above packer	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Annulus Fluid Volume (bbl)	Volumetric measurement	Wellhead	As needed	Monthly	Semi-Annual	Monthly Total
CO_2 Stream Temperature (deg F)	Electronic Thermocouple	Wellhead	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
CO_2 Stream Temperature (deg F)	Distributed thermal sensing system	Temperature profile along entire well	Continuous (min every 10 sec)	Monthly	Semi-Annual	Single monthly profile measured while injecting
Injection Pressure at Formation (psi)	Pressure Gauge	Downhole gauge within 20 ft of top perforation	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum
Temperature at Formation (deg F)	Temperature Sensor	Downhole sensor within 20 ft of top perforation	Continuous (min every 10 sec)	Monthly	Semi-Annual	Average, Minimum, Maximum

2.2 System Monitoring Details

Injection operations parameters recorded on a continuous basis in Table 2 must be connected to the main facility through a supervisory control and data acquisition (SCADA) system to record the operations data, control injection rates, or initiate system shutdown, if needed.

Continuous recording devices must monitor wellhead injection pressure, temperature, and mass flow rate (40 CFR 146.90(b)). The injection flow rate must be directly measured at the surface to calculate the cumulative mass of injected CO_2 and ensure compliance with the permit injection limits. The injection volume must be calculated using the mass flow rate combined with the pressure and temperature conditions in the injection zone. The calculated injection volumes must, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project as detailed in Attachment B.

The tubing – casing annular (TCA) pressure between the tubing and the injection casing string as well as the annular fluid volumes must also be monitored on a continuous basis (40 CFR 146.90(b)). The volume of the annulus fluid between the injection tubing and the long-string casing must be measured using the accumulator levels and the brine reservoir level on the well-control system. The accumulator and brine reservoir levels must be measured using a level transmitter. The transmitters must be connected to the well-control system and to the SCADA system. A significant change in the fluid volume in the accumulator or brine reservoir (i.e., fluid is being pumped from the reservoir to the annulus or fluid being pushed out of the annular space) during routine injection operations may be an indication of well integrity problems, as the fluid volumes would normally remain relatively constant, and must require further investigation.

Pressure differential between the annulus and the tubing at the depth of the packer must be calculated by the Permittee.

2.3 Injection Rate and Pressure Monitoring

The CO_2 injection pressure must be monitored on a continuous basis at the wellhead and downhole at the depth of the Lyons Sandstone Formation. If the downhole injection pressure exceeds 95% of the downhole maximum allowable injection pressure at any point, then the injection process must be automatically shut down per Attachments A and F of the Permit.

Any anomalies outside of the normal operating specifications may indicate that an issue has occurred within the well, such as a loss of mechanical integrity or blockage in the tubing or may be caused by a change in injection flow rate. Anomalous pressure measurements will trigger further investigation by the Permittee of the cause of the change. The downhole injection pressures will also be used to calibrate the computational modeling throughout the injection phase and PISC phase of the project.

The SCADA system will limit the downhole pressure to the MAIP listed in Attachment A of this permit. All injection operations must be continuously monitored and controlled by the Permittee using the SCADA system. This system must continuously monitor, control, record, and must alarm and shutdown if specified control parameters exceed their normal operating range. The operating conditions, parameters, limits, and alarm set points are found in Attachment A, Tables 1 and 2.

2.4 Calculation of Injection Volumes

The injection volume into the reservoir must be calculated on a continuous basis based on the injection mass and the pressure and temperature conditions in the injection zone. The volumetric flow rate of CO_2 injected into the well must be measured by a volumetric flow meter and flow computer. The flow computer must have digital output. The flow meter must be connected to the SCADA system for continuous monitoring and control of the CO_2 injection rate into the well. The flow meter must be calibrated at the frequency recommended by the manufacturer. The volume of CO_2 injected must be calculated from the mass flow rate obtained from the volumetric flow meter and flow computer. The mass flow rate must be calculated based on the pressure differential, temperature, and pressure data. This flow meter must be placed on the CO_2 delivery line downstream of the compressor.

2.5 Continuous Monitoring of Annular Pressure

The Permittee must use the procedures below to monitor annular pressure. The following procedures must be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1. The tubing casing annulus (TCA) must be filled corrosion resistant fluid. The fluid must have a specific gravity and a density that meets the requirements of the downhole conditions.
2. The TCA pressure, as measured at the wellhead, must be kept at a minimum of 100 pounds per square inch (psi) at all times. During injection, as measured at the surface, the TCA pressure must maintain a minimum of 100 above the tubing pressure. See Attachment A, Table 1.
3. The pressure in the annular space directly above the packer must be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

After the initial standard annulus pressure test (SAPT), the annular pressure must be continuously monitored throughout the operational period in conjunction with the annular pressure monitoring and control system. The pressure on the annulus between the injection tubing and the long-string casing must be measured by an electronic pressure transducer with analog output that is mounted on the wing valve/annular fluid line connected to the wellhead of FR 1-1. The transmitter must be connected to the well control system and the SCADA system to regulate the annular pressure. Sudden changes in the annular pressure during routine injection operations are a sign of potential tubing or tubing packer integrity issues that will trigger further investigation through mechanical integrity testing.

3.0 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), the Permittee must monitor well materials during the operational 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.

3.1 Monitoring location and frequency

Monitoring must occur using corrosion coupons collected on a quarterly basis during the injection period and sent for analysis in accordance with NACE (National Association of Corrosion Engineers) Standard SP-0775-2023. If the coupon corrosion rate is 0.1 mm/year or greater, the Director must be notified within 7 days and a casing inspection log must be conducted within 60 days. The Director may require additional testing and/or increased monitoring.

In addition to using corrosion coupons, the Permittee must conduct visual inspections of the well and evaluate monitoring data for potential fluid movement that could result from corrosion. Monitoring results must be documented and submitted to the EPA as per 40 CFR 146.91(a)(7) and, if appropriate, 40 CFR 146.91(c).

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

3.2 Sample description

Samples of material used in the construction of the compression equipment, flowline, FR 1-1 injection well, and FR 2-1 deep-zone monitoring well which come into contact with the carbon dioxide stream must 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 3 below. Each coupon must be weighed, measured, and photographed prior to initial exposure (see "Sample Handling and Monitoring" below).

Table 3: List of equipment coupon with material of construction

Equipment Coupon	Material of Construction
Flowline	Carbon Steel, API 5L X52 PSL2
Long String Casing	Martensitic Stainless Steel, 13CR-L80 - UNS S42000
Injection Tubing	Martensitic Stainless Steel, 13CR-L80 - UNS S42000
Wellhead	Carbon Steel, API 5L X52 PSL2
Packer	Superalloy Steel Alloy 925 - UNS N09925

3.3 Monitoring details

Samples of well construction materials (coupons) and monitoring well materials must be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Representative materials must be weighed, measured, and photographed prior to installation. Coupons must be analyzed in accordance with NACE Standard SP-0775- 2023 to determine and document corrosion wear rates based on mass loss. A summary of coupon parameters is shown in Table 4.

Table 4: Summary of Analytical Parameters for Corrosion Coupons.

Parameter	Analytical Method
Mass	NACE SP0775-2023[a]
Thickness	NACE SP0775-2023[a]

[a] NACE SP0775-2023: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations.

3.4 Casing Inspection Logs

Permittee must perform casing inspection logging (CIL) during planned well maintenance on the FR 1-1 and FR 2-1, unless the Director waives this requirement due to well construction or other factors which limit the test's reliability or based upon the satisfactory results of a casing inspection log run within the previous five years. Between planned maintenance events, Permittee may conduct CIL if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards. The Director may require that a casing inspection log be run every five years, if the Director has reason to believe that the integrity of the long string casing of the well may be adversely affected.

3.5 Surface Detection Methods

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

The Permittee must perform additional optical analysis using Optical Gas Imaging (OGI) cameras quarterly during the injection period. OGI cameras use infrared images to detect gas leaks and must be used during the inspection of facilities and pipelines connected to the Class VI wells, and well locations.

4.0 Groundwater Monitoring

The Permittee must monitor USDW groundwater quality and geochemical changes in the injection zone and above and below the upper and lower confining zones, the Entrada Formation and Ingleside Formation, respectively, during the operation period to meet the requirements of 40 CFR 146.90(d) and 146.95(f). The Permittee must also monitor groundwater quality and geochemical changes in the shallow USDWs (Quarternary and Pierre Formation), as well as pressure. Front Range 2-1 (FR 2-1) will be used to take fluid samples and monitor pressure changes in the Entrada and Ingleside Formations.

Pressure in the adjacent monitoring zones will be monitored from the wellhead. The gauge will record and transmit data to the SCADA system continuously.

All testing and monitoring must be conducted in accordance with the requirements of this permit, and the procedures must adhere to the Quality Assurance and Surveillance Plan (QASP) in Attachment I.

Pressures in the FR 2-1 monitoring well will be monitored at the wellhead. Migration of CO_2 or brine into the monitored formation would likely first be identified through pressure changes in the formation. An increasing pressure trend in the monitored zones would suggest that fluid movement across the confining zone has occurred. Any increasing trend in pressure must be evaluated, and an increase in pressure that deviates more than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid movement out of the injection zone. Such a change in pressure will initiate more frequent fluid sampling and analysis for aqueous geochemistry from the monitoring zones as well as additional external well integrity investigations for FR 2-1 as determined by the Director. Anomalous pressure or geochemical changes may trigger the need for additional well integrity testing for FR 2-1 as determined by the Director. These results may require an update to the Testing and Monitoring Plan. Anomalous changes adjacent to the confining zone may also trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F.

If anomalous changes in aqueous geochemistry are observed in the monitoring interval, the Permittee must obtain new samples from the affected formation to verify the changes. Changes of greater than 25% in the value of the above parameters, not attributable to natural or seasonal fluctuations, will require the Permittee to acquire new samples. Such changes in these parameters may also trigger the need for analyses of isotopic compositions.

4.1 Monitoring location

There are 6 monitoring stations (MS-1 through MS-6) depicted in Figure 2 that are spatially distributed within the AoR. Each monitoring station includes a shallow alluvial groundwater monitoring well (SMW-1 through SMW-6) and three additional deeper Pierre monitoring wells (DMW-1 through DMW-3) are found in monitoring stations MS-1 through MS-3. Front Range 2-1 is the dedicated groundwater monitoring well that has been drilled into the lowermost USDW (40 CFR 146.90(d)). Table 5 provides a summary of these groundwater wells.

Baseline shallow groundwater quality samples has been collected from existing shallow groundwater wells within the AoR to characterize the seasonal variations in groundwater quality within the AoR. The project must have surface access rights to the land to sample the shallow groundwater wells as part of the landowner leases for the project.

Front Range 2-1 is monitoring well for the Lyons Sandstone injection interval and USDWs immediately above and below the injection zone. The well will provide direct measurements of pressure and fluid composition in the Lyons and the Entrada and Ingleside Formations, as well as indirect geophysical measurements of the CO_2 plume. Its location is between the modeled Year 5 and Year 8 plume perimeters and outside the Year 12 pressure front, allowing early plume detection while minimizing pressure-driven risk to USDWs.

Figure 2. Front Range 1-1 monitoring well and shallow groundwater wells within the AoR.

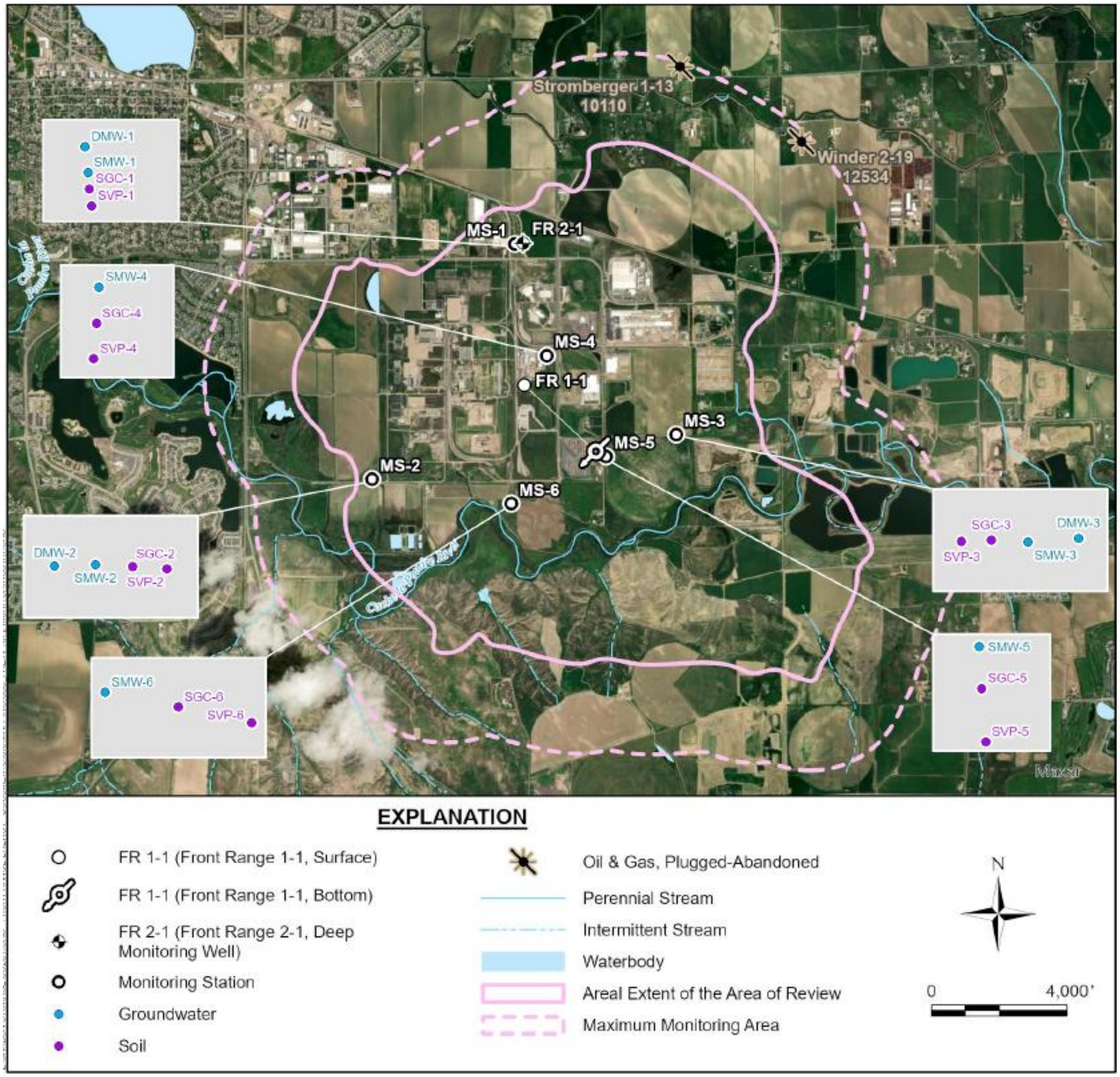


Table 5: Groundwater sample wells

Target Formations	Monitoring Activity	Monitoring Locations	Spatial Coverage
Alluvial aquifer (water table aquifer), Upper Pierre (USDW)	Groundwater Quality and Geochemical Monitoring	SMW-1, DMW-1 SMW-2, DMW-2 SMW-3, DMW-3 SMW-4 SMW-5 SMW-6	Grid of single point measurements within the AoR/MMA1 and vicinity
Entrada Sandstone, Ingleside	Geochemical Monitoring	Front Range 2-1	Single point measurements

[1]Maximum Monitoring Area (MMA) equals AoR plus ½ mile

4.2 Groundwater sampling

Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry analyses must be compared to the baseline conditions for any indication of CO_2 or formation fluid migration into USDWs. If indications of CO_2 or brine are found in a USDW, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F.

4.2.1 Sampling and analytical methods

During pre-operational testing, the carbon isotopic composition of the CO_2 stream, the USDWs, and the fluids of the monitored zones, must be measured to determine baseline values.

Groundwater monitoring samples must be collected according to Section E.I.2.2 of the QASP of the permit application. Prior to sample collection the well must be flushed to remove stagnant water from the well and ensure representative water is collected from the formation. The fluid removed from the well must be monitored for the field parameters listed in Table 6. Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Sample handling and custody must be performed as described in Section E.I.2.3 of the QASP. Quality Control (QC) will be ensured using the methods described in Section E.I.2.5 of the QASP.

Table 6: Summary of parameters and analytical methods for groundwater samples

Parameters	Analytical Methods
Formation: Alluvial Aquifer and Pierre Shale	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K,v Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric Titration ASTM D513-11
Total Dissolved Solids	Gravimetry APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Entrada, Ingleside	
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
Dissolved CO_2	Coulometric Titration
	ASTM D513-11
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

Parameters	Analytical Methods
	2510
Temperature (field)	Thermocouple
Formation: Lyons	
Cations: Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Ni, potassium, Se, SiO2, Si, Ag, Na, Sr, V, Zn	ICP EPA Method 6010
Anions: Br, Cl, F, NO3, nitrite, and SO4	Ion Chromatography EPA Method 300.0
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
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 CaCO3)	SM 2320B
pH	SM 4500
Total sulfide and sulfide as H2S	SM 4500
Total CO2 SM 4500	SM 4501
Cyanide SM 4500	SM 4502
Total organic carbon	SM 5310C

4.2.3 Laboratory to be used/chain of custody procedures

The laboratories selected must meet all requirements set forth in the Testing and Monitoring Plan and the QASP. The Chain-of-Custody procedures follow the requirements of Section E.I.2.3 of the QASP.

4.3 Summary of Monitoring Well Requirements

Table 7 provides a summary of the groundwater, soil/gas, and vertical seismic profile monitoring wells and stations, objectives, methods, and frequencies.

Table 7: Monitoring Requirements for Front Range Storage Complex Monitoring Wells and Stations

Objective	Method	Event Frequency	Record/Report Frequency/Requirement	Reporting Parameter
Front Range 2-1				
Monitor annular pressure	Gauge at wellhead and down hole above packer	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of pressure and temperature to detect CO_2	Downhole pressure and temperature gauge	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
Direct monitoring of fluids to detect CO_2 in the Lyons, Entrada, and Ingleside	Geochemical analysis (Table 6, Attachment C)	Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually	Year 1-2: Annually; Year 3-8: Quarterly; Remainder: Annually	Analytical Results
Indirect monitoring of CO_2 plume	Pulsed Neutron Log (PNL)	Annually	Annually	PNL
Indirect monitoring of CO_2 plume	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Indirect monitoring of CO_2 presence above the Injection Zone	Time-lapse Vertical Seismic Profile (VSP)	At least every five years, plus one at end of period	At least every five years, plus one at end of period	VSP surveys
Internal mechanical integrity	Downhole pressure gauge	Continuous (minimum reading every 10 seconds)	Record Monthly Report Semi-annual	Average, Minimum, Maximum
	SAPT: See Table 8. Attachment C	See Table 8, Attachment C	Within 30 days of conducting test	MIT results
External mechanical integrity	See Table 8. Attachment C	Annually	Within 30 days of conducting test	MIT results
Corrosion monitoring	Fluid corrosivity testing (pH, chloride, O2)	Quarterly	Quarterly	Any changes from proposed operating data
Groundwater Monitoring Wells (SMW and DMW Wells)				
Groundwater Quality	Water level (pressure), temperature, conductivity, and salinity	Continuous (minimum reading every 30 minutes)	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Average, Minimum, Maximum
Geochemical and isotopic monitoring to detect CO2	See Table 6. Attachment C	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Year 1-2: Quarterly; Year 3-5: Semi-annually; Remainder: Annually	Analytical results
Soil Gas Monitoring Wells; Surface Air Monitoring Stations				
Surface leak detection	See Table 9 & 10 - Attachment C	See Table 9 - Attachment C	See Table 9 - Attachment C	Analytical results; Average, Minimum, Maximum

4.3.1 Sampling Schedule

During the injection phase of the project, fluids from these wells must be sampled according to the frequency found in Table 7.

The schedule of sampling is as follows:

1. Continuous: Data is continuously sampled and recorded per the frequency.
2. Quarterly: Sampling will take place within 5 days before the following dates each year: March 31st, June 30th, September 30th, December 31st.
3. Semi-annual: Sampling will take place within 5 days before June 30th and December 31st.
4. Annual: Sampling will take place within 45 days before January 1st of each year.
5. 5 Year: Sampling will take place every 5 years within 45 days before January 1st during injection and the PISC period.

Reporting procedures

The Permittee must report the results of all testing and monitoring activities to the Director in compliance with this attachment, the requirements under 40 CFR 146.91, and Section O of this Permit.

5.0 Internal and External Mechanical Integrity Testing

Permittee must conduct tests to verify the internal and external mechanical integrity (MI) of the FR 1-1 injection well and the FR 2-1 monitoring well before and during the injection phase pursuant to 40 CFR 146.87(a)(4), 40 CFR 146.89, 40 CFR 146.90(e), and 40 CFR 146.92(a).

The purpose of internal mechanical integrity testing is to confirm the absence of significant fluid movement within the injection tubing, casing, or packers (40 CFR 146.89(a)(1)). Continuous monitoring of injection pressure and pressure must be used to demonstrate internal mechanical integrity. In addition, annulus pressure tests must be conducted at the frequencies listed in Table 8 to demonstrate internal mechanical integrity.

The purpose of external mechanical integrity testing is to confirm the absence of significant fluid movement or fluid movement outside of the casing into or between USDWs (40 CFR 146.89(a)(2)). Permittee must conduct logging using an approved external mechanical integrity testing method in the injection well and deep-zone monitoring well on an annual basis to demonstrate external mechanical integrity. Permittee may choose which logging and testing to demonstrate external mechanical integrity but must continue to use that same test for the remainder of the project.

Well logging and testing procedures must be submitted and approved by the Director prior conducting any test or log. EPA approved procedure guidance can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy . Other procedures may be approved by the Director.

Well logs and test results must be submitted to the Director within 30 calendar days of the logging or testing activity completion and must include a report describing the methods used during logging or testing and an interpretation of the log or test results by a knowledgeable log analyst. When applicable, the interpretative report must also include detailed analysis of: (1) USDWs and adjacent confining zone(s) and (2) the injection zone and adjacent confining zone(s).

5.1 Mechanical Integrity Testing Location and Frequency

Table 8 below provides a summary of the internal and external mechanical integrity tests, locations, and frequencies for the FR 1-1 injection well and FR 2-1 deep-zone monitoring well.

To demonstrate internal mechanical integrity of the wells, the Permittee must perform an annulus pressure test prior to injection and after any well maintenance operations which affects the tubing, packer, or casing. Annulus pressure monitoring must be performed on the wells continuously thereafter. Additional testing must be conducted if the pressure or temperature data collected from gauges indicate a potential loss in mechanical integrity as determined by the Director.

Table 8: Mechanical Integrity Test and Monitoring Descriptions, Location, and Frequency

Test Description	Well	Measurement Location	MIT Frequency
Standard Annulus Pressure Test (SAPT) - Internal	FR 1-1	Wellhead	Prior to Authorization to Inject & after workover or loss of MI
	FR 2-1	Wellhead	
Annular Pressure and Temperature Monitoring – Internal	FR 1-1	Surface and Bottomhole	Continuous
	FR 2-1	Surface and Bottomhole	Continuous
Temp/Noise/OA[1] - External	FR 1-1	Full Wellbore	Annually[2]
	FR 2-1	Full Wellbore	Annually[2]

[1] Permittee can select the external test method, but must continue to use the same test for the remainder of the project life.
[2]At least once every 12 months after last successful test

6.0 Pressure Fall-Off Testing

A pressure fall-off test (PFOT) must be conducted in the Lyons Sandstone Formation in FR 1-1 prior to authorization to inject to establish the hydrogeologic characteristics of the injection zone. Permittee must perform PFOTs during the injection phase at least once every five years unless more frequent testing is required by the Director based on site-specific information as required by 40 CFR 146.90(f). The formation characteristics obtained through the PFOT must be compared to the results of previous tests to identify any changes over time, and must be used to calibrate the computational model. Pressure fall-off test procedures must be submitted and approved by the Director prior to conducting any test. EPA approved procedure guidance can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/guideline.pdf. Other procedures may be approved by the Director.

7.0 Carbon Dioxide Plume and Pressure Front Tracking

Permittee must employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure throughout the life of the project to meet the requirements of 40 CFR146.95(f)(3)(ii). A summary of the methods used for CO_2 and pressure front tracking is provided in **Error! Reference source not found.**7.

7.1 Monitoring Location and Frequency

The Lyons Formation Injection Zone must be directly monitored using the FR 2-1 monitoring well. The monitoring well was drilled prior to the commencement of CO_2 injection and is located within the Area of Review.

Table 7 describes the monitoring methods and measurement frequencies utilized throughout the Project's life. Quality assurance procedures for these methods are found in the QASP. The results from direct and indirect methods must be utilized to calibrate the computational model for AoR re-evaluation.

7.2 Description of Methods

Additional new technologies may be considered in coordination with the Director and may be added to the Testing and Monitoring Plan if approved. Any amendments to the Testing and Monitoring Plan must be approved by the Director and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

Fluid and dissolved gas sampling must be collected to establish a baseline. These samples must be analyzed for their geochemical composition and isotopic characterization. If anomalous pressure and/or temperature changes are observed in an injection and monitoring wells during injection or post-injection, fluid samples and/or dissolved gas samples must be obtained for geochemical and isotopic analysis and compared with pre-injection samples.

7.2.1 Geochemical Monitoring

Geochemical monitoring must be employed in Front Range 2-1 monitoring well to monitor the injection zone and adjacent USDWs above and below. These data must be compared with the pre-injection geochemical and isotopic characterization to evaluate whether changes are observed. If changes are measured, then Permittee must assess whether the compositional changes are likely to be the result of naturally occurring biological processes or another source. If sampling results indicate a potential migration of the CO_2 stream or formation fluids from the injection zone into a USDW, or other unauthorized zone, the Permittee must notify the Director within 24 hours.

7.2.2 Pressure and Temperature Monitoring

Pressure and temperature gauges are deployed on the tubing above and below the packer that isolates to injection zone to monitor downhole conditions in real time. In the Front Range 2-1 well, the gauges and cables must be selected to withstand CO_2 service conditions as determined by the Director. Permittee must evaluate the data semiannually and interpret the results. If a sudden change in pressure or temperature is observed, Permittee must immediately cease injection, notify the Director within 24 hours, and evaluate and identify the cause of the change.

7.2.3 Saturation Detection Tool Method

Pulsed neutron logging (PNL) must be run in FR 2-1 to monitor CO_2 saturations and vertical plume development adjacent to the wellbore annually. The PNL data must be used to verify when the leading edge of the CO_2 plume reaches the observation well. This logging can also be used to identify the presence of CO_2 above the confining zone should there be fluid movement along the wellbore.

7.3 Seismic Methods

Permittee must use time-lapse Vertical Seismic Profiling (VSP) as the indirect geophysical method to image CO_2 plume evolution in the Lyons Sandstone. Baseline data are processed to build a reference model; repeat surveys are then compared against the baseline to track amplitude, frequency, phase, and time delay changes indicative of fluid substitution in the reservoir.

7.3.1 Baseline Seismic Acquisition and Frequency

- Baseline: Acquire a single pre-injection baseline VSP over the maximum monitoring area (MMA) and vicinity to establish the reference seismic state prior to CO_2 injection.
- Injection period: The Testing and Monitoring Plan schedules time-lapse VSP coincident with AoR re-evaluation, plus one survey at the end of the injection period.
- Post Injection Site Care: Continue time-lapse VSP coincident with AoR re-evaluation during PISC, with one survey at the end of PISC to confirm stability prior to site closure, consistent with the Post Injection Site Care Plan schedule.

8.0 Near-Surface Soil and Soil Gas Sampling *[40 CFR 146.90(h)]*

The primary objectives of near-surface soil and soil gas monitoring are to confirm containment of CO_2 within the Lyons Formation, and to provide early detection of anomalous conditions indicative of potential fluid movement of CO_2, for the ultimate objective of detecting fluid movement that could endanger a USDW**.**

8.1 Monitoring Location and Frequency

Subsurface soil gas probes must be installed at approximately six (6) representative locations throughout the AoR shown in Table 9.

The Permittee must collect and analyze soil gas samples for gas and isotopic parameters prior to CO_2 injection to determine a characteristic profile for the site. During the injection phase, soil gas must be monitored for gas composition during the Project's life. If anomalous pressure and/or temperature changes are observed in the nearby Front Range 1-1 or monitoring well(s), or there is any indication of fluid movement through the injection well, additional soil gas samples must be collected for gas composition and/or isotopic analysis and comparison to pre-injection sample results.

Table 9: Soil Gas Monitoring Locations and Frequency

Monitoring Activity	Monitoring Locations	Spatial Coverage	Sample Frequency	Record Frequency	Reporting Frequency
Monitor soil gas CO_2 across a network of stations	SCSW-1 SCSW-2 SCSW-3 SCSW-4 SCSW-5 SCSW-6	Single point Measurements within AoR/MMA[2] and vicinity	Continuous[1]	Monthly	Semi-annually
Laboratory Analysis of Samples from Network of Stations	SVP-1 SVP-2 SVP-3 SVP-4 SVP-5 SVP-6	Single point measurements within AoR/MMA[2] and vicinity	Quarterly	Quarterly	Semi-annually
CO_2 Efflux Measurements at Each Station	MS-1, MS-2, MS-3, MS-4, MS-5, MS-6	4x4 grid of single point measurements within AoR/MMA[2] and vicinity	Quarterly	Quarterly	Semi-annually

[1]Continuous is defined as measurements taken at 30-minute intervals, with a 6-hr averaged reading recorded
[2]Maximum Monitoring Area (MMA) equals AoR plus ½ mile.

8.2 Description of Methods

Table 10 contains the analytes and their approved analytical method.

Table 10: Summary of analytes and methods for soil gas 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
$\delta\ ^{13}C$ 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 – GM 500 or equivalent) – internal electrochemical cell
Carbon Monoxide – field	Field Meter (Landtec – GM 500 or equivalent) – internal electrochemical cell
Hydrogen Sulfide – field	Field Meter (Landtec – GM 500 or equivalent) – internal electrochemical cell

9.0 Seismicity and Fault Monitoring

9.1 Monitoring for Natural and Induced Seismicity

The Permittee must monitor the site with USGS seismic monitoring network for the duration of the Project through site closure to ensure the protection of USDWs, while also ensuring the safe operation of both the storage facility and adjacent infrastructure in the area.

If a seismicity event is detected, the Permittee must implement the response plan defined below to eliminate or reduce the magnitude of damage to the injection well or deep-zone monitoring well . Refer to the Emergency and Remedial Response Plan (Attachment F of this Permit) for action thresholds and specific steps.

9.2 Seismicity Monitoring Network

Permittee must 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 4.6 of the Emergency and Remedial Response Plan. Report summary of monthly reviews of seismic event(s) within a fifty (50) mile radius of the area permit boundary, gathered from the USGS Earthquake Hazard Program website or personal communication with the semi-annual report.

The United States Geological Survey (USGS) network must be continuously monitored during Injection for validated triggering events. The response to triggering and validated triggering events is defined in Attachment F, Section 4.6 of the Emergency and Remedial Response Plan.

10.0 Reporting Requirements

The Permittee must report to the Director all testing and monitoring performed pursuant to this Permit, consistent with 40 CFR 146.90 and 146.91 and in Section O of this Permit. Unless otherwise specified, discrete test results (e.g., mechanical integrity tests, PFOTs, injectate analyses, tracer tests) must be submitted within thirty (30) calendar days of completion of the test, including supporting data, methods, calibrations, and interpretations sufficient for Director review.

The report submittal schedule is (determined on a calendar basis):

- Quarterly Reports due on or before April 30th, July 31st, October 31st, January 31st of the preceding quarter.
- Semiannual Reports due on or before July 31st for first reporting period and January 31st for second reporting period
- Annual Reports due on or before January 31st
- 5-year reports due on or before February 15th of the end of the 5-year reporting cycle (from January 1st year 1 to December 31st year 5)

ATTACHMENT D: WELL PLUGGING PLAN

This attachment includes the Well Plugging Plan required by 40 CFR 146.92 for the injection well and requirements for plugging the deep-zone monitoring well in accordance with CFR 146.93(e). Plugging operations must be conducted in a manner that prevents the movement of fluids into or between underground sources of drinking water (USDWs) and ensures long-term isolation of the injection zone and other permeable formations penetrated by the wellbore.

1.0 General Requirements

1. Before beginning the plugging process, the bottomhole reservoir pressure needed to conduct cementing must be determined from a bottomhole pressure gauge and used to evaluate the pressure needed to conduct cementing operations.
2. The Permittee must conduct final external mechanical integrity tests (MIT) prior to plugging as required by Section L.2(f) of this Permit consistent with 40 CFR 146.92(a) and (b)(2). A temperature survey, oxygen-activation log, noise log, or other approved external MIT log must be run over the entire well depth and must be consistent with previous methods of testing used during the injection and post-injection site care periods. An annulus pressure test must be conducted to determine internal MIT in accordance with Section 5.0 of Attachment C. If a failure in the long string casing is identified, the Permittee must repair the issue before plugging for Director review and approval.
3. Prior to plugging, the permittee must stabilize the well and verify that formation pressures have been controlled. The wells must be flushed with buffer fluid and if needed, kill fluid. Kill fluids must be at least 10 pounds per gallon (ppg) sodium chloride (NaCl) brine. A minimum of three tubing volumes must be injected without exceeding the formation fracture pressure.
4. Tubing, packers, and other completion equipment must be removed to allow proper placement of cement plugs.
5. During plugging operations, a heavy-weighted cement slurry, as well as weighted displacement fluids, must be over-balanced to ensure that no reservoir fluids will enter the wellbore during cementing operations.
6. Once plugging is complete, the casing must be cut 5 feet below ground level. A metal cap must be welded onto the top of the cut casing, stamped with the well name and API number. The surface location must then be backfilled and restored to pre-operation conditions.
7. The owner or operator must notify the Director in writing, at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan.

The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41.

8. Within 60 days after plugging, the owner or operator must submit a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator must retain the well plugging report for 10 years following site closure.

2.0 Plugging Plan for the Front Range 1-1 Injection Well

After serving as an injection well, Front Range 1-1 must be re-purposed as a monitoring well for the post-injection site care (PISC) period. The Front Range 1-1 well must be plugged and abandoned after completion of its use as a monitoring well for the PISC period.

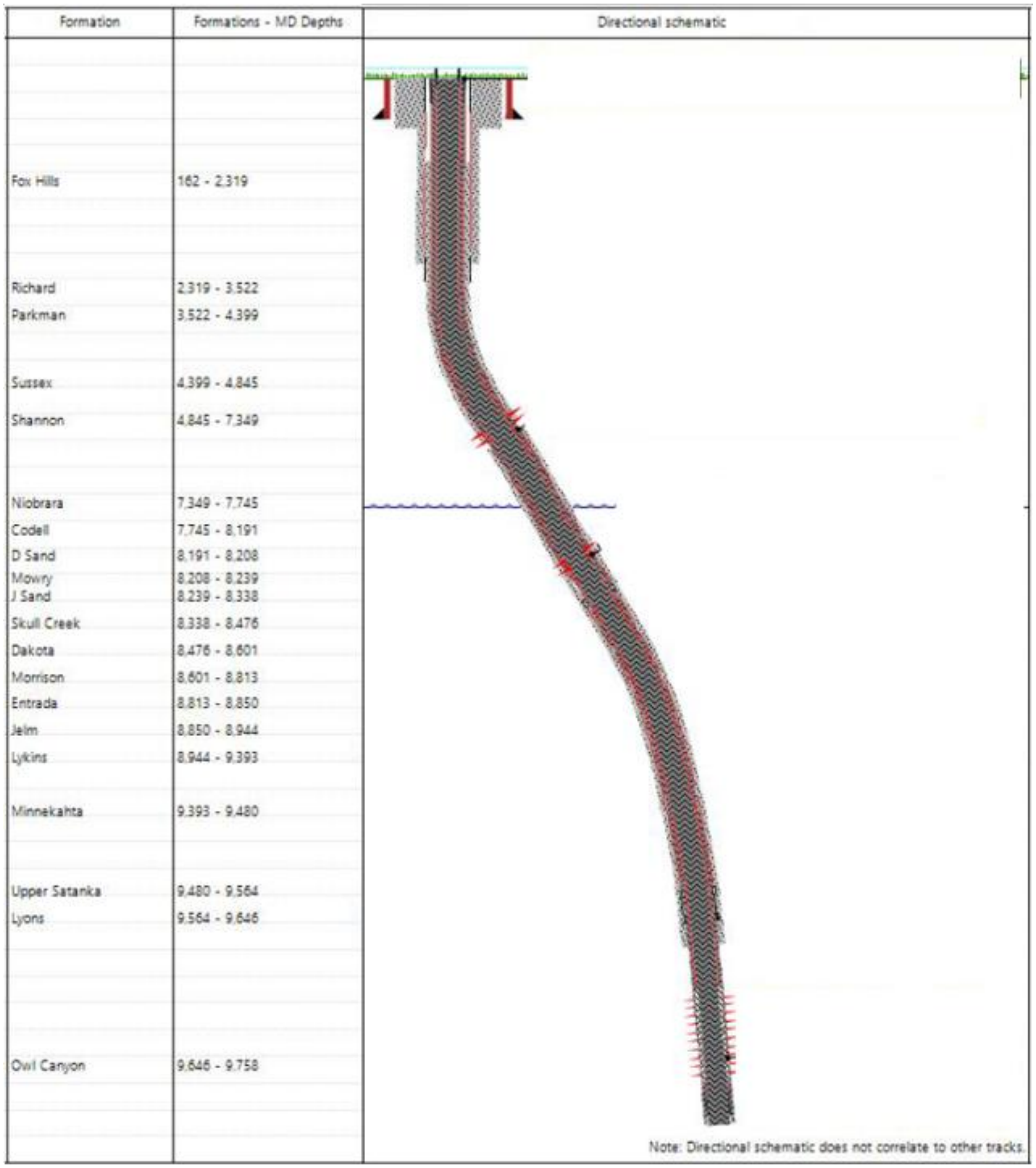
1. The well must be cemented continuously from bottom to the surface. Cement must be squeezed into the injection zone perforations. After squeezing the injection zone, cement must be placed continuously above the injection zone plug to the surface (plugs 1 and 2). Plugs may be placed in multiple lifts to achieve continuous cement.

2. Permittee must use the materials and methods listed in Table 1. The cement formulated for plugging the injection zone and plug 1 must be compatible with the CO_2 stream. The cement formulation, including details of all proposed additives and their quantities, and required certification documents must be submitted to the Director. Permittee must report the wet density and retain duplicate samples of the cement used for each plug.

Table 1. Plugging Details for Front Range 1-1

Plug Information	Injection Zone	Plug #1 (Lifts 1-6)	Plug #2 (Lifts 8-19)
Diameter of casing in which plug will be placed (inches)	6.184	6.184	6.184
Depth to casing bottom (feet)	9,746	9,746	9,746
Calculated depth to plug top (feet)	9,370	6,030	0
Depth to plug bottom (feet)	9,746	9,370	5,990
Sacks of cement	60	576	1,053
Slurry volume (cubic feet)	75	757	1,208
Slurry weight (pounds per gallon)	15	15	15.8
Cement type	CO_2 Resistant (CORROSACEM or equivalent)	CO_2 Resistant (CORROSACEM or equivalent)	Class G
Method of emplacement	Squeezed	Pumped	Pumped

Figure 1: Front Range 1-1 well plugging schematic



5.0 Plugging Plan for Front Range 2-1 Monitoring Well

1. The well must be cemented continuously from bottom to the surface. Cement must be squeezed into the perforated intervals for the Ingleside Formation, Lyons Sandstone, and Entrada Sandstone (plugs 1–3). After squeezing the perforated intervals, cement must be placed continuously above the plugged perforated intervals to the surface (plug 4). Plugs may be placed using multiple lifts to

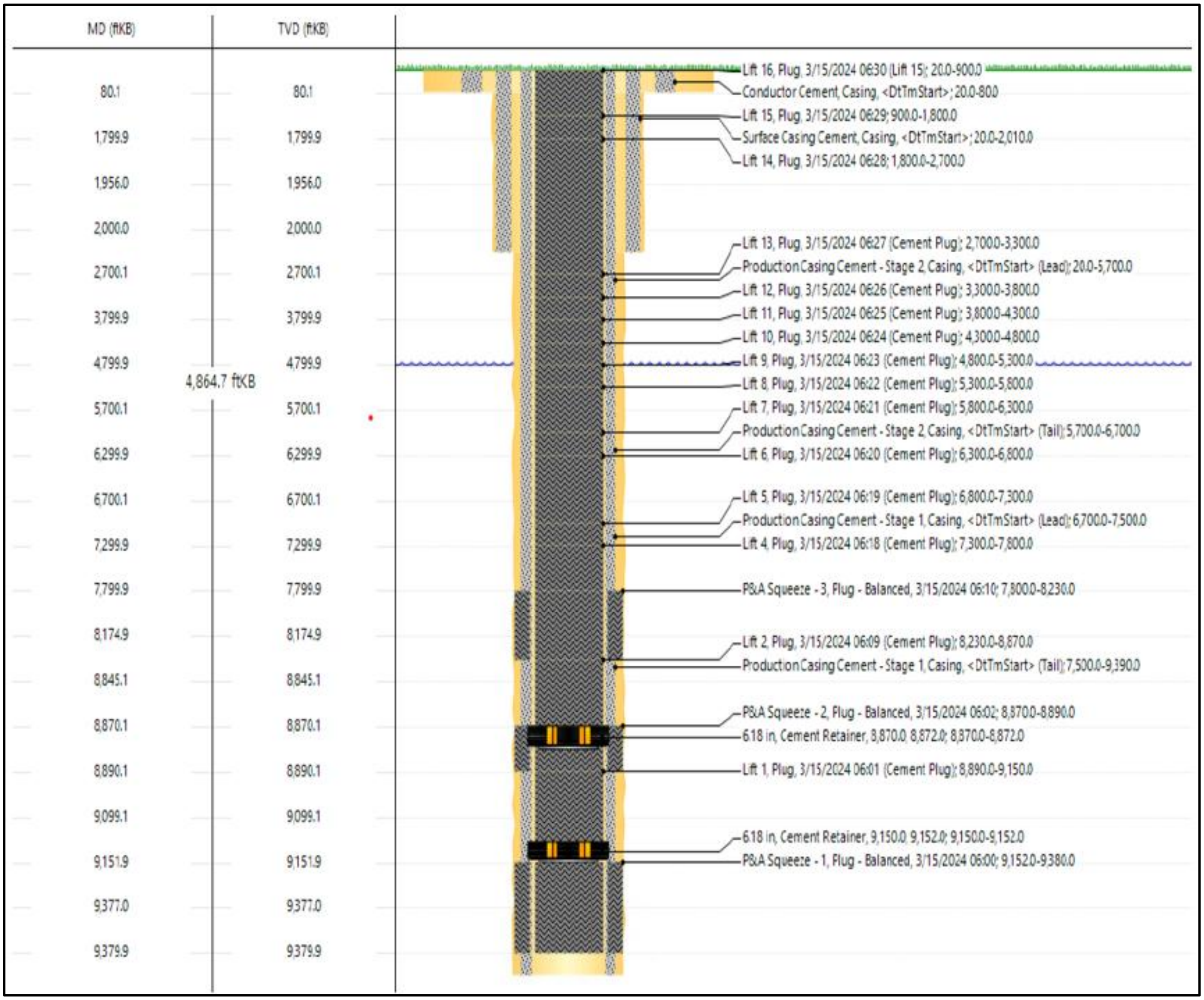
achieve continuous cement.

2. Permittee must use the materials and methods listed in Table 2. The cement formulated for plugging the perforated intervals (plugs 1–3) must be compatible with the CO_2 stream. The cement formulation, including details of all proposed additives and their quantities, and required certification documents must be submitted to the Director. Permittee must report the wet density and retain duplicate samples of the cement used for each plug.

Table 2. Plugging plan for Front Range 2-1.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of casing in which plug will be placed (inches)	6.18	6.18	6.18	6.18
Depth to casing bottom (feet)	9,380	9,380	9,380	9,380
Calculated depth to plug top (feet)	8,890	8,230	7,800	0
Depth to plug bottom (feet)	9,380	8,890	8,230	7,800
Sacks of cement	104	187	82	1,937
Slurry volume (cubic feet)	142	282	124	2,925
Slurry weight (pounds per gallon)	14.5	14.5	14.5	14.5
Cement type	CO_2 Resistant	CO_2 Resistant	CO_2 Resistant	Class G
Method of emplacement	Squeezed and pumped	Squeezed and pumped	Squeezed and pumped	Pumped

Figure 2: Front Range 2-1 well plugging schematic



ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

1.0 Plan Overview

This attachment includes the post-injection site care (PISC) and site closure plan requirements consistent with 40 CFR 146.93. This plan must be updated at a minimum every five (5) years and submitted to the Director for approval.

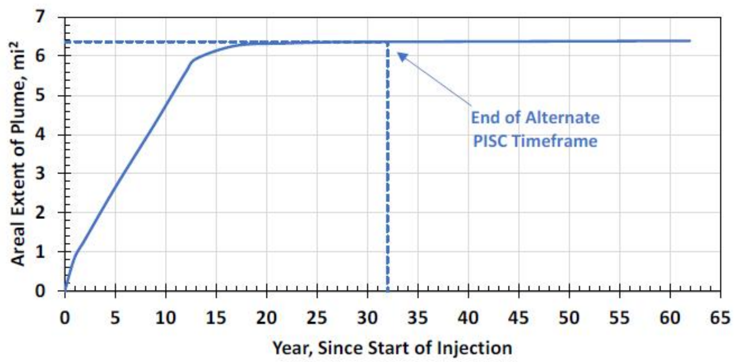
1. The Permittee must monitor groundwater quality and track the position of the CO_2 plume and pressure front for twenty (20) years, or for another approved alternative timeframe approved by the UIC Program Director in accordance with 40 CFR 146.93(b)(2).
2. The Permittee must continue post-injection site care until the Director approves cessation of monitoring and site closure under 40 CFR 146.93.
3. Following approval for site closure, the Permittee must plug the Front Range 1-1 and Front Range 2-1 monitoring wells and submit a site closure report with all required documentation.

2.0 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR §146.93(a)(2)(ii)]

Computational modeling indicates that after injection ceases, the predicted CO_2 plume remains within the Lyons Formation, and the area does not expand over time. The colored area in Figure 1 shows the CO_2 plume extent in Year 32, as defined by the global mole fraction of CO_2. Figure 2 shows cross-section of the Lyons Formation with the CO_2 global mole fraction at the end of the injection period at Year 32. There is some minor vertical migration of CO_2 to upper portions of the Injection Zone due to buoyancy forces. The AoR is defined by the plume shape and size in Year 12 (end of injection period) because this is the time with the largest differential pressure and CO_2 plume. All pressure is predicted to have been reduced to levels below the level of endangerment to USDWs by Year 32. Therefore, Year 32 (20 years post-injection) is predicted to be the site closure date.

The map in Figure 1 is based on the final AoR delineation modeling results submitted pursuant to 40 CFR §146.84.

Year, Since Start of Injection	Areal Extent of Plume, mi^2	Rate of Expansion, mi^2/yr
0	0.00	-
1	0.86	0.86
2	1.31	0.45
5	2.64	0.44
9	4.30	0.41
12	5.59	0.43
13	5.93	0.34
17	6.27	0.09
22	6.33	0.01
27	6.36	0.01
32	***6.37***	***0.00***
62	6.39	0.00



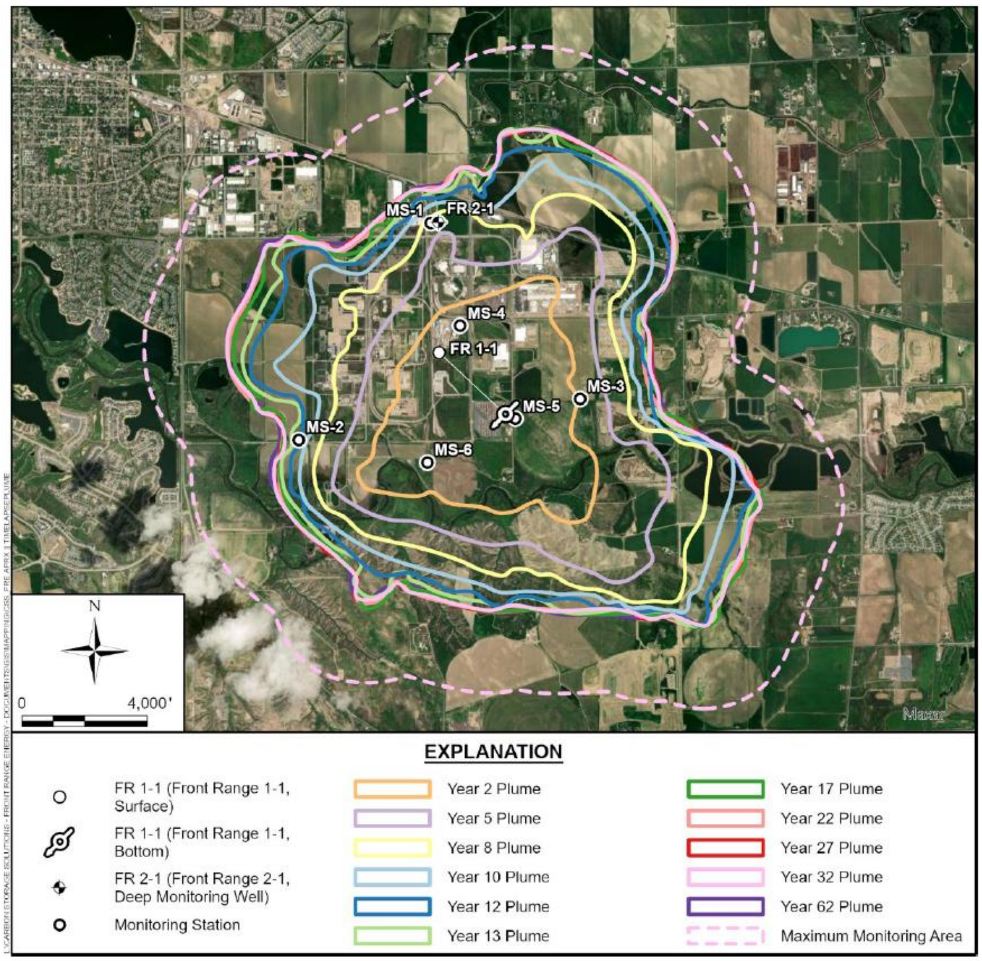


Figure 1: Areal extent of the CO_2 plume at site closure in Year 32 since start of CO_2 injection. graph of Areal, in mi^2, shows plume expansion ends in year 32.

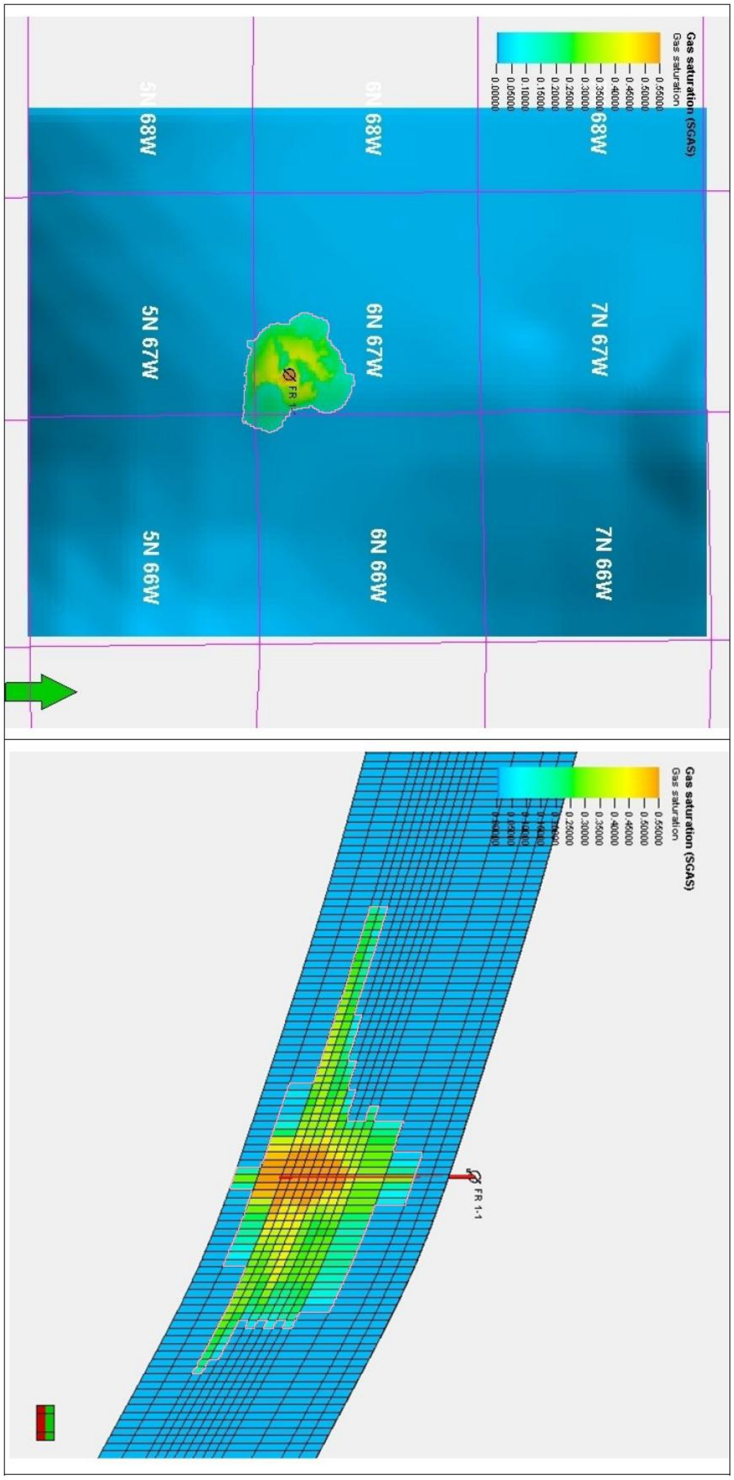


Figure 2: Vertical extent of the CO_2 plume at site closure in Year 32 since start of CO_2 injection. CO_2 plume remains in the Lyons Formation.

3.0 Post-Injection Monitoring Plan [40 CFR §146.93(a)(2)(iii)]

As described in the following sections, groundwater quality monitoring and plume and pressure-front tracking during the post-injection phase must meet the requirements below, consistent with 40 CFR §146.93(b)(1).

The results of all post-injection phase testing and monitoring must be submitted according to permit requirements. (40 CFR §146.93(a)(2)(iv)).

The Permittee must comply with the following requirements:

1. After the injection ceases, the Injector well must be converted to a monitoring well.
2. The first 10 years after the cessation of injection, direct measurements of pressure and temperature in the Injection Zone, the Entrada Formation, and Ingleside Formations must be obtained from the FR 1-1 and FR 2-1 monitoring wells that have not yet been plugged. Fluid samples must be collected every 5 years, and more frequent fluid samples must be collected if pressure or temperature indicate a change as determined by the Director.
3. Annual Pulsed Neutron Log must be conducted in FR 1-1 and FR 2-1 wells until plugging.
4. Time-lapse vertical seismic profile (VSP) data must be collected in the FR 1-1 injection well and FR 2-1 deep-zone monitoring well, coincident with AoR reevaluation and once at the end of the PISC period.

3.1 *Monitoring Above and Below the Injection Zone*

The required monitoring methods, locations, and frequencies for monitoring above the upper and lower Confining Zone are included in Table 1 below.

Table 1: Post-Injection Monitoring Techniques in/above the Confining Zone

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
USDWs above and below the confining zone monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annual	Record: Annually Report: Annually
Soil Gas Monitoring	Monitor soil gas CO_2 across a network of stations	Single point measurements within AoR/MMA and vicinity	Continuous	Record: Monthly Average, Min, and Max Report: Semi Annually
FR 1-1 and FR 2-1	Confirming integrity of the Upper and Lower Confining Zone	Saturation logging (pulsed neutron logging)	Annual until plugging	Report: Annually
		Distributed thermal sensing	Continuous	Record: Single Monthly Profile Report: 6 monthly profiles Semi Annually

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

<u>3.2 *Carbon Dioxide Plume and Pressure Front Tracking [40 CFR §146.93(b)(1) and 146.95(f)(4)]*</u>

The Permittee must employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure. Table 2 presents the direct and indirect methods that the Permittee must use to monitor the CO_2 plume, including the activities, locations, and frequencies. Fluid sampling, sampling handling and custody, quality control, and quality assurance must be performed as described in the QASP.

Table 2: Post-Injection Monitoring Techniques Plume and Pressure Front Tracking

Location	Objective	Method	PISC Monitoring	Recording and Reporting Frequency
FR 1-1 FR 2-1	Fluid and dissolved gas chemistry	Fluid and dissolved gas sampling via wireline	Event-driven* until plugging	After any event, record and report to the Director
	Direct monitoring of pressure and temperature to ensure seal integrity	Pressure and temperature gauges or distributed thermal sensing	Continuously	Record: Monthly Average, Min, and Max Report: Semi Annually
	Indirect monitoring of CO_2 concentration	Pulsed neutron log	Annually until plugging	Report within 30 days of test
	Plume and pressure extent over time	Vertical seismic profile	At least every five-year, coincident with AoR Review until plugging or plume stabilization	Report after acquisition
	External mechanical integrity	Pressure and temperature gauges; external MIT	MIT log at least every five-year period and before plugging	Report within 30 days of test
	Surface leak detection	Visual inspection at wellhead, optical gas imaging, cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure	Record: Any leakage Report: Any leakage and submit quarterly inspection report
	Indirect monitoring of CO_2 presence above the Injection Zone	Pulsed neutron log	Event-driven* until plugging	After any event, record and report to the Director
	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annually	Record: Annually Report: Annually
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at a minimum of 15 locations	Event-driven*, triggered by P/T data or fluid sample results	After any event, record and report to the Director

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

3.3 *Schedule for Submitting Post-Injection Monitoring Results [40 CFR §146.93(a)(2)(iv)]*

During the PISC period, monitoring reports must be prepared and submitted to the Director per Section O of the Permit. These reports must contain the information established pursuant to Sections 3.1 and 3.2 of this Plan.

Permittee must reevaluate the AoR at a minimum fixed frequency not to exceed five years during the post-injection phase. Permittee may be required to review the AoR earlier than the established fixed frequency when warranted by certain monitoring and operational conditions (40 CFR 146.84(b)(2)(ii)) during post-injection phase. The PISC and Site Closure Plan must be reviewed at a minimum fixed frequency not to exceed five years during the PISC period.

Permittee must submit an update to the PISC plan to the Director:

(a) as necessary to address new information collected during the logging and testing of the well and the formation prior to authorization to inject;

(b) during the operation of the well(s), if warranted through a review of the AoR;

(c) at the cessation of injection, Permittee must either submit an amended PISC or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed; and

(d) in the case of monitoring results that indicate a need for proposed changes to the PISC plan, Permittee must submit a modified plan to the Director for approval within 30 days of receipt such data results.

Prior to authorization for site closure, Permittee must submit a demonstration based on monitoring and other site-specific data that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.

The operational and monitoring results must be reviewed by the Permittee consistent with the objectives of the PISC. The monitoring locations, methods, and schedule must be analyzed in relation to the size of the CO_2 Injection Zone, pressure front, and protection of USDWs.

4.0 Non-Endangerment Demonstration Criteria (40 CFR 146.93(b)(3)

Prior to authorization for site closure, the Permittee must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the Front Range Storage Complex does not pose an endangerment to USDWs. The Permittee must submit a report to the Director that will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the Front Range Storage Complex computational model. The report must detail how the non-endangerment evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report must include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis. At a minimum, the report must contain all of the elements listed below:

4.1 Summary of Existing Monitoring Data

The required report must summarize all previous monitoring data collected pursuant to this PISC and Site Closure Plan and explain how it supports a non-endangerment demonstration. Data should be compared with baseline data collected during site characterization (40 CFR 146.82(a)(6) and 146.87(d)(3)).

4.2 Summary of Computational Modeling History

The report must compare the computational modeling results used for the AoR delineation with the monitoring data collected during the operational and PISC periods. Monitoring data must also be compared with baseline data collected during the site characterization required under 40 CFR §146.82(a)(6) and §146.87(d)(3).

The data must be used to update the computational model and monitor the site and must include both direct and indirect geophysical methods. Direct methods include measurements of pressure, temperature, fluid and dissolved gas chemistry. Indirect methods include time-lapse vertical seismic profile (VSP) and saturation logging using pulsed neutron logging (PNL).

Data generated during the PISC period must be used to show that the computational model accurately represents the storage site and can be used as a process to determine the plume's properties and size.

The Permittee must demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods must be employed to correlate the data and confirm the model's ability to represent the storage site accurately. The validation of the computational model with the large quantity of measured data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the entire area, and at the points where direct data collection has taken place, will ensure confidence in the model for those areas with no direct observation wells where the surface infrastructure precludes geophysical data collection.

4.3 Evaluation of Reservoir Pressure

The report must demonstrate non-endangerment to USDWs by showing that the pressure within the Injection Zone has decreased to levels within 1 percent of its pre-injection static reservoir pressure during the PISC period.

The Permittee must monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval must be compared with the pressure predicted by the computational model, which was previously shown in Figure 1 and Figure 2. Agreement between the actual and predicted values will validate the accuracy of the model and further demonstrate non-endangerment.

4.4 Evaluation of Carbon Dioxide Plume

The report must use a combination of monitoring data, logs, geophysical surveys, and seismic methods to locate and track the movement of the CO_2 plume. The data produced by these activities must be compared with the modeled predictions (Figure 1 and 2) using statistical methods to validate the model's ability to represent the storage site accurately. PISC monitoring data must be used to show the stabilization of the CO_2 plume as the reservoir pressure returns to its near-pre-injection state. The risk to USDWs will decrease when the extent of pure-phase CO_2 ceases to grow either laterally or vertically. The stabilization of the CO_2 plume combined with the lack of unmitigated artificial penetrations in the confining formation will be significant factors in the Project's demonstration of non-endangerment.

Fluids and dissolved gases collected from monitoring wells or soil or soil gas samples may be used to determine aqueous-phase CO_2 concentrations and mobilized constituents to assess USDW endangerment. If a demonstration can be made that the majority of the CO_2 has been immobilized via trapping mechanisms, then there is strong evidence that the risk to USDWs posed by the CO_2 plume has decreased. Modeling results, including sensitivity analyses, may also be used to demonstrate that plume migration rates are negligible based on available site characterization, monitoring, and operational data.

4.5 Evaluation of Emergencies or Other Events

In addition to the CO_2 plume, mobilized fluids may also pose a risk to USDWs, as the reservoir fluids include brines that are high in total dissolved solids (TDS) and contain hydrogen sulfide. The geochemical data collected from monitoring wells must be used to demonstrate that no mobilized fluids have moved above the upper confining zone and therefore would not pose a risk to USDWs after the PISC period. Monitoring data indicating steady or decreasing trends of potential drinking water contaminants below actionable levels (e.g., secondary, and maximum contaminant levels) will be used for this demonstration.

To demonstrate non-endangerment, the Permittee must compare the operational and PISC period fluid and dissolved gas samples from the lowermost USDW with the pre-injection baseline samples. This comparison is expected to show chemical similarity to baseline samples. Changes in chemistry must be evaluated to demonstrate attribution. This work must demonstrate the absence of CO_2 injectate or brine forced from the Injection Zone into the lowermost USDW.

Corrective action must be performed on artificial penetrations identified to be potential leak pathways. Based on this information, the potential for fluid movement through artificial penetrations of the confining formation does not present a risk of endangerment to any USDWs.

5.0 Site Closure Plan

The Permittee must conduct site closure activities to meet the requirements of 40 CFR §146.93(e) as described below. The Permittee must submit a final Site Closure Plan and notify the permitting agency at least 120 days in advance of its intent to close the site. At this time, if any changes have been made to the original post-injection site care and site closure plan, the Permittee must also provide the revised plan. Once the Director has approved site closure consistent with the process in P.6(a) of the Permit, the Permittee must plug all monitoring wells and submit a site closure report to Director within 90 days of site closure. The activities described below represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan must be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

5.1 Plugging Monitoring Wells (40 CFR 146.93(e))

Upon receiving authorization for site closure from the Director, all monitoring wells must be plugged within 90 days of site closure. All Injection Zone monitoring wells at the site must be plugged and abandoned using best practices to prevent any upward migration of the CO_2 or communication of fluids between the Injection Zone and USDWs. The deep-zone monitoring well in the Injection Zone has a direct connection between the injection formation and the ground surface; therefore, the well plugging program is specifically designed to prevent communication between the Injection Zone and USDWs. Details of the plugging program are found in Attachment D.

Before the well is plugged, the internal and external mechanical integrity of the well must be confirmed by conducting a pressure test and a cement and casing inspection log. The results of this logging and testing must be reviewed and approved by the appropriate regulatory agencies before plugging the wells.

Infrastructure removal and site restoration efforts must comply with applicable state and local requirements.

5.2 Site Closure Report (40 CFR 146.93(f))

A Site Closure Report (SCR) must be prepared and submitted to the Director within 90 days after site closure. The SCR must document the following aspects of the site closure process:

(a) Plugging of all injection and monitoring wells as required at 40 CFR 146.92 and 146.93 (e);

(b) Details of site restoration activities;

(c) Location of the sealed injection well on a survey plat submitted to the local zoning authority, a copy of which must be sent to the Regional Administrator for EPA Region 8. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks

(d) Notifications sent to state and local authorities as required at 40 CFR 146.93(f)(2);

(e) Records reflecting the nature, composition, and volume of CO_2 injected;

(f) Records of pre-injection, injection, and post-injection monitoring;

(g) Certifications that all injection and storage activities have been completed; and

(h) A demonstration that the Permittee has met the deed notation requirements in Section 5.3 of this Attachment.

The site closure report must be submitted to the Director and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator must maintain the records collected during the post-injection site care period for a period of 10 years after which these records must be delivered to the Director.

5.3 Notation of Deed

The Permittee must record a notation on the deed of the property on which the injection well was located, which must include the following:

(a) The fact that the property was used for carbon dioxide sequestration;

(b) The name of the local agency with which the survey plat was filed as well as the address of the EPA regional office to which it was submitted;
(c) The volume of fluid injected;
(d) The Injection Zone or zones into which the fluid was injected; and
(e) The period over which the injection occurred.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP)

1.0 Plan Overview

This attachment includes the permit requirements to address and remediate events that could allow for movement of the injected carbon dioxide (CO_2) stream, annulus fluid, or formation fluid including, but not limited to, any movement of fluid into an Underground Source of Drinking Water (USDW) or any other unauthorized zones during the operation or post-injection site care (PISC) periods for the injection well.

1.1 Endangerment Requirements - In accordance with 40 CFR 146.94(b), if the Permittee obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, the Permittee must perform the following actions:

(a) Initiate the shutdown plan for the injection well.
(b) Take all steps reasonably necessary to identify and characterize any release.
(c) Notify the permitting agency Underground Injection Control (UIC) Program Director of the emergency event within 24 hours.
(d) Implement applicable portions of the approved ERRP.

1.2 Shutdown Plan Initiation - Where the phrase "initiate shutdown plan" is used, the following protocol must be employed:

(a) Permittee must immediately cease injection, unless gradual cessation of injection is necessary for safety.
(b) Shut in the well (all necessary valves closed and locked out).
(c) Vent CO_2 from surface lines and facility as necessary.
(d) Limit access to wellhead and surface facilities to only those authorized (caution tape and/or rope may be used to limit access to the well and facility).

As used in this ERRP, the term "wells," unless otherwise specified, refers to the injection well and all monitoring wells. As used in this ERRP, the term "Area of Review" or "AoR," unless otherwise specified, refers to the AoR as defined in the Permit.

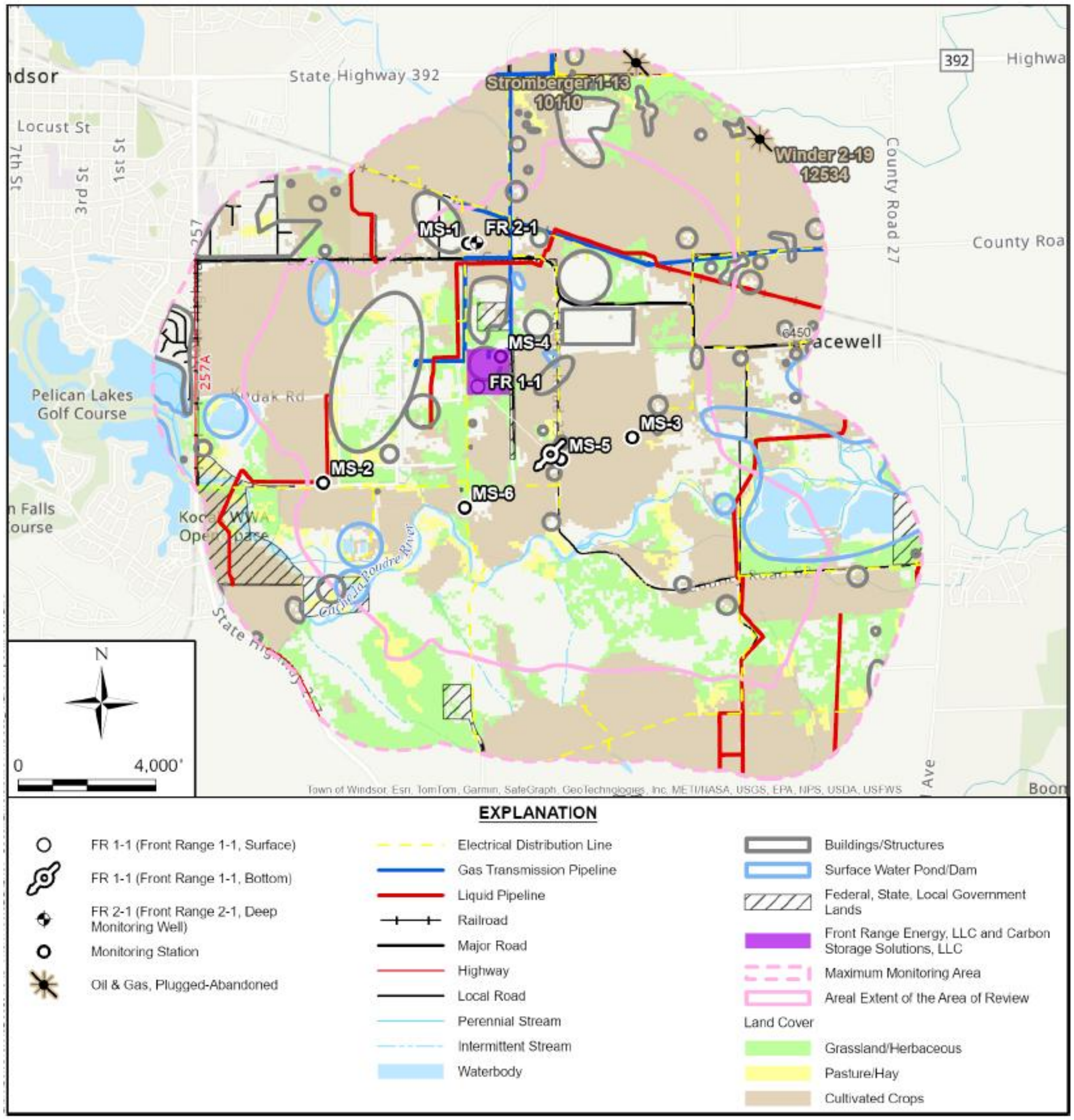
2.0 Local Resources and Infrastructure

The infrastructure integral to the project includes the injection well Front Range 1-1, the deep-zone monitoring well Front Range 2-1, and multiple monitoring stations labeled MS-1 through MS-6. Additionally, surface facilities are located at the Carbon Storage Solutions, LLC site, where the injection well is located, and the adjacent Front Range Energy, LLC site, where the CO_2 is produced

Land resources in the region are varied, comprising grasslands, herbaceous lands, pasture/hay lands, and cultivated crop lands, as identified by the United States National Land Cover Database for 2021. While public lands are present, indicated by black hatch marks on maps, there are no nature preserves within or near the geologic sequestration site. The built environment is mixed-use development and includes multiple industrial and residential buildings.

Surface water resources include the Cache de la Poudre River, unnamed tributaries, and several surface ponds. The AoR and Corrective Action Plan (Attachment B of this Permit) provides further details about the USDWs in the project area. Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of surface features within the area of review (current as of February 28, 2026)



3.0 Potential Risk Scenarios

The following events related to the Project that could potentially result in an emergency response are included in Table 1. This table lists the types of potential adverse incidents that will trigger response actions to protect USDWs and prevent injected CO_2 stream, annulus fluid, or formation fluid migration into any unauthorized zones if the incidents occur during the injection through post-injection site care periods. The Permittee must undertake emergency or remedial actions in response to these incidents. This is a non-exhaustive list of potential risk scenario events.

Table 1: Potential Emergency Events

Injection Period

• Well integrity failure
  ○ Loss of mechanical well integrity due to casing, tubing or packer leak in injection well
  ○ Loss of mechanical well integrity due to casing leak in the monitoring wells
  ○ Loss of external mechanical well integrity from metal leaching or corrosion due to prolonged wetted CO_2 exposure in injection or monitoring wells
• Well control event during well rework with loss of containment
• Potential fluid movement to USDW
  ○ Vertical migration of fluids from the Injection Zone through plugged and abandoned (P&A'd) or undocumented wells
  ○ Vertical migration of fluids from the Injection Zone through failure of the confining zone and/or faults, and fractures (loss of containment)
• Well monitoring equipment failure or malfunction (e.g., shutoff valve or pressure gauge)

Post-Injection Site Care Period

• Well control event during plugging and abandonment with loss of containment
• Well integrity failure
  ○ Loss of mechanical well integrity due to casing leak in the monitoring wells
• Potential fluid movement to USDW
  ○ Vertical migration of fluids from the Injection Zone through plugged and abandoned (P&A'd) or undocumented wells
  ○ Vertical migration of fluids from the Injection Zone through failure of the confining zone and/or faults, and fractures (loss of containment)

Throughout the Life of the Project
• Severe weather disaster (e.g., tornado, hurricane, lightning strike) • Seismic event other than a microseismic event • Other emergency at or near the wellsite (e.g. pipeline rupture).

4.0 Emergency Identification and Response Actions

The Permittee must report to the Director within 24 hours if there is any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW; any noncompliance with a Permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs; any triggering of a shut-off system; any failure to maintain mechanical integrity; or surface air/soil gas monitoring detection that indicates CO_2 may have been released into the shallow subsurface and/or atmosphere.

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. Emergency identification and response actions for the potential risk scenarios identified in Table 1 are detailed below.

In accordance with Permit section K.11, the Permittee must obtain written approval to resume injection after any cease injection event.

4.1 Well Mechanical Integrity Failure

Loss of mechanical integrity in the injection and/or monitoring wells may endanger USDWs, including endangerment due to the movement of the injected CO_2 stream, annulus fluid, or formation fluid into an unauthorized zone.

Integrity loss may have occurred if the following events occur (note, this is not an exhaustive list):

- Automatic shutdown devices are activated.
  - Wellhead pressure exceeds the shutdown pressure specified in the Permit.
  - Annulus pressure indicates a loss of well containment.
- Mechanical integrity test results identify a loss of mechanical integrity.
  - Loss of mechanical integrity due to a casing, tubing or packer leak in the injection well.
  - Loss of mechanical integrity due to a casing leak in the monitoring wells.

4.1.1 If there is a loss of mechanical integrity for the Front Range 1-1 or Front Range 2-1 wells, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Initiate shutdown plan.

(c) Monitor tubing and annulus pressures and temperature, as is feasible. This information should be used to assess and determine the nature or cause and extent of the mechanical integrity failure.

(d) Identify and implement appropriate remedial actions to repair damage to the well in consultation with the Director.

(e) If the loss of mechanical integrity has resulted in a failure of monitoring equipment, implement response actions.

(f) If there is evidence suggesting potential fluid movement into a USDW or unauthorized zone, implement response actions

(g) Perform mechanical integrity test.

(h) Perform any other appropriate response actions.

4.2 Well Control Event

Loss of containment could occur during well rework or plugging and abandonment operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well.

If there is a well control event, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Cease injection.

(c) Close blow off prevention.

(d) Limit access to wellhead and surface facilities to only those authorized (caution tape and/or rope may be used to limit access to the well and facility) Execute well control procedure.

(e) Perform any other appropriate response actions.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors.

4.3 Well Monitoring Equipment Failure or Malfunction

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure, including malfunctioning monitoring well, may indicate a problem that could pose a risk of endangerment to USDWs.

This subsection covers the response and procedures that must be followed should one (or more) of the following monitoring sensors fail:

- Injection Well
  - Injection pressure and temperature gauge
  - Annulus pressure
  - Annulus fluid volume
  - Injection flow rate
- Deep-Zone Monitoring Well
  - Annulus pressure
  - Annulus fluid volume
  - Formation pressure
  - Formation temperature
- Shallow Monitoring Wells
  - Groundwater samples

4.3.1 If there is a failure or malfunction of well monitoring equipment of the Front Range 1-1 and Front Range 2-1 monitoring well, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Determine the impact of the event, based on the information available, within 24 hours of the event occurring. Assess the impact of the loss of monitoring equipment and determine and implement a viable alternative monitoring method in consultation with the Director.

(c) If there has been a loss of mechanical integrity, implement Response Actions from Section

4.1.

(d) Assess whether there is evidence suggesting potential fluid movement into a USDW or unauthorized zone, and if there is such evidence, implement response actions in Section 4.4.

(e) In consultation with the Director, assess whether monitoring capabilities at the project are sufficient to ensure non-endangerment to USDWs. If monitoring capabilities are not sufficient, treat the event as an immediate risk. If the event poses an immediate or near-term risk to human health, resources (including USDWs), or infrastructure, the Permittee must initiate shutdown plan in Section 1.2 of this attachment.

(f) Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information should be used to assess and determine the nature or cause and extent of the failure.

(g) Replace equipment (if needed) as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring.

(h) Identify and implement appropriate remedial actions to repair the well in consultation with the Director. Perform any other appropriate response actions.

4.3.2 If there is a failure or malfunction of well monitoring equipment at any of the shallow groundwater wells, the Permittee must:

(a) Notify the Director about the event within one week.

(b) Identify an alternative monitoring method as appropriate in consultation with the Director.

(c) Perform any other appropriate response actions.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors

4.4 Evidence Suggesting Potential Fluid Movement into a USDW or Other Unauthorized Zone

Potential injected CO_2 stream, annulus fluid, or formation fluid movement into a USDW or other unauthorized zones may endanger USDWs. This scenario includes but is not limited to:

- Elevated concentrations CO_2 in groundwater sample(s) or other evidence suggesting potential fluid movement into a USDW or other unauthorized zone (including the surface).
- Unanticipated emergency corrective action(s) needed on a well(s) within the AoR.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid between formations through the injection, and/or monitoring wells, including due to metal leaching or corrosion due to prolonged wetted CO_2 exposure.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid from the Injection Zone through plugged and abandoned wells or undocumented wells in the AoR.
- Evidence of migration of injected CO_2 stream, annulus fluid, or formation fluid from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment).

4.4.1 If the Permittee obtains evidence of potential injected CO_2 stream, annulus fluid, or formation fluid movement into a USDW or other unauthorized zone, the Permittee must:

(a) Notify the Director about the emergency event within 24 hours.

(b) Initiate shutdown plan if the event poses an immediate or near-term risk to human health, resources (including USDWs), or infrastructure.

(c) Monitor wellhead pressure (tubing and annulus) and temperature as is feasible. This information must be used to assess and determine the nature or cause and extent of the failure.

(d) Take all steps reasonably necessary to identify and characterize any release.

(e) Collect confirmation samples from USDWs or any other potentially relevant formation(s) and analyze the sample to determine elevated analytes parameters.

4.4.2 If the presence of leaked fluid or other contamination is confirmed in a USDW or other unauthorized zone, the Permittee must:

(a) Identify and begin implementing a remediation plan in consultation with the Director, as soon as possible and no later than 30 days of the emergency event.

(b) Arrange for an alternate potable water supply within 24 hours if the USDW was being utilized for water supply and the contamination has caused an exceedance of drinking water standards.

(c) Continue USDW monitoring on a frequent basis in consultation with the Director, until potential endangerment of or adverse impacts to USDWs have been fully addressed.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors

4.5 Severe Weather Disaster

Well problems (mechanical integrity loss, fluid movement, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the FR 1-1 and FR 2-1 wells. Weather-related disasters may affect project facilities.

If there is a severe weather event affecting the project facilities, the Permittee must:

(a) Notify the Director within 24 hours.

(b) Trigger alarm by the monitoring system or monitoring personnel.

(c) If appropriate, contact the field superintendent to activate emergency evacuation and secure the location.

(d) Determine if there has been a loss of mechanical integrity. If there has been a loss of mechanical integrity, implement Response Actions from Section 4.1.

(e) Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3.

(f) Conduct assessment to determine if there is evidence suggesting potential fluid fluid movement into a USDW or unauthorized zone. If there is such evidence, implement

Response Actions from Section 4.4.

(g) Assess potential impact to the Project, local resources and infrastructure.

(h) Identify and implement appropriate remedial actions in consultation with the Director.

Response personnel: Initial response by site personnel, remediation by Permittee and its subcontractors.

4.6 Seismic Events

The Permittee must implement the response action in Table 2 below is based on moment magnitude (Mw) thresholds and potential damage:

Table 2: Seismic Monitoring System, for Seismic Events >Mw 1.0

Operational Status	Moment Magnitude (Mw)[a,b]	Responses
Green	Seismic events where Mw <= 1.5	1. Continue normal operation within permitted levels.
Yellow	Five or more seismic events within a 30-day period where 1.5 < Mw <= 2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause.
Orange	Seismic event where Mw > 1.5 and local observation or felt report Seismic event where Mw > 2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the Director of the operating status of the well. 3. Review seismic and operational data to determine the cause. 4. Report findings to the Director and identify and implement appropriate remedial actions in consultation with the Director.
Magenta	Seismic event where Mw > 2.0 and local observation or felt report	1. Initiate rate reduction plan in consultation with the Director. 2. Within 24 hours of the event, notify the Director of the operating status of the well. 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans, if necessary. 5. Review seismic and operational data to determine the cause of the event. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate actions in consultation with the Director.

		8. If there has been a loss mechanical integrity at any of the wells, implement response actions from Section 4.1. 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3. 10. Conduct assessment to determine if there is evidence suggesting potential fluid movement into a USDW or unauthorized zone. If there is such evidence, implement Response Actions from Section 4.4.
Red	Seismic event where Mw > 2.0, and local report and confirmation of damage Seismic event where Mw > 3.5	1. Initiate shutdown plan. 2. Within 24 hours of the incident, notify the Director of the situation. 3. Limit access to wellhead to authorized personnel only. 4. Communicate with facility personnel and local authorities to initiate evacuation plans. 5. Review seismic and operational data to determine the cause of the event. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the extent of any failure. 7. Report findings to the Director and identify and implement appropriate remedial actions in consultation with the Director. 8. If there has been a loss of mechanical integrity, implement Response Actions from Section 4.1. 9. Determine if all monitoring equipment remains functional. If there has been a failure of monitoring equipment, implement Response Actions from Section 4.3. 10. Conduct assessment to determine if there is evidence suggesting potential fluid movement into a USDW or unauthorized zone. If there is such evidence, implement response actions from Section 4.4.

[a] Specified magnitudes refer to magnitudes determined by US Geological Survey or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[b] "Felt report" and "local observation or report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[c] Remedial action must occur within 5 days.

5.0 Response Personnel and Equipment

Site and project personnel will be relied upon to implement this ERRP. It is the Permittee's responsibility to ensure appropriate personnel will implement the ERRP and that local authorities will be engaged by personnel in an appropriate and timely manner to manage emergencies. It is the responsibility of the Permittee to ensure all identified personnel are familiar with the procedures of the ERRP. Emergency drills should be conducted annually and include participation of the local authorities.

A site-specific emergency contact list must be developed and maintained during the life of the project and at a minimum, annually updated. Table 3 identifies the key contacts and their phone numbers.

Table 3: Contact Information for Key Local, State, and Other Authorities

Entity	Phone Number
Police	
Emergency	911
Main – Windsor Police Department (non-emergency)	(970) 686-7476
Fire	
Emergency	911
Main – Windsor Severance City (non-emergency)	(970) 686-9594 or (970) 686-2626
Weld County Emergency Planning Commission Dispatch	(970) 356-4015 ext. 2700
Colorado State Emergency Response Commission Greg Stasinos (CEPC Co-Chair)	(303) 692-3023
Colorado Department of Public Health & Environment 24-Hour Spill Hotline	(877) 518-5608
Colorado Division of Oil and Public Safety	(303) 318-8547
Colorado Energy and Carbon Management Commission	(888) 235-1101
Colorado/Occupational Safety and Health Administration	(303) 844-5285
US EPA National Response Center (24-hour)	(800) 424-8802
US EPA Region 8	
UIC Enforcement Supervisor – Tiffany Cantor	(303) 312-6521
Emergency Operations Center	(303) 293-1788, or (800) 227-8917

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, the Permittee must be responsible for its procurement.

6.0 Emergency Communications Plan

The Permittee must communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

The Permittee must describe what happened, impacts to the environment or other local resources, how the event was investigated, what response actions were taken, and the status of the response. For responses that occur over the long term (e.g., ongoing cleanups), the Permittee must provide periodic updates on the progress of the response action(s).

The Permittee must communicate with entities who need to be informed about or act in response to the event, including local water systems, CO_2 source(s), pipeline operators, landowners, and regional response teams (as part of the National Response Team).

7.0 Plan Review

In accordance with 40 CFR 146.94(d), the Permittee must periodically review the ERRP. Based on this review, the Permittee must submit an amended ERRP or a demonstration to the Director that no amendment is needed. Any amendments to the ERRP must be approved by the Director to be effective, and if approved, must be incorporated into the Permit by modification. Amended plans or demonstrations must be submitted to the Director as follows:

a. At least once every five (5) years following its approval by the Director;

b. Within one (1) year of an area of review re-evaluation;

c. Following any significant changes to the facility, such as an addition of injection or monitoring wells, on a schedule determined by the Director; or

d. Within six (6) months following the occurrence of an emergency event under this ERRP, and

e. When required by the Director.

8.0 Staff Training and Exercise Procedures

The Permittee must integrate the ERRP into the plant-specific standard operating procedures and training program. All operations employees, well operators, project safety and environmental personnel, the project manager, plant operations supervisor, and corporate communications must receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training must be conducted by, or under the supervision of, the operations manager or a designated representative. Trainers must be thoroughly familiar with the Operations Plan and ERRP.

Refresher training must be conducted at least annually. New personnel must be instructed before beginning their work. Monthly briefings must be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

A record including the person’s name, date of training, and instructor’s signature must be maintained. These records may be requested by the Director and made available upon request.

ATTACHMENT G: WELL CONSTRUCTION

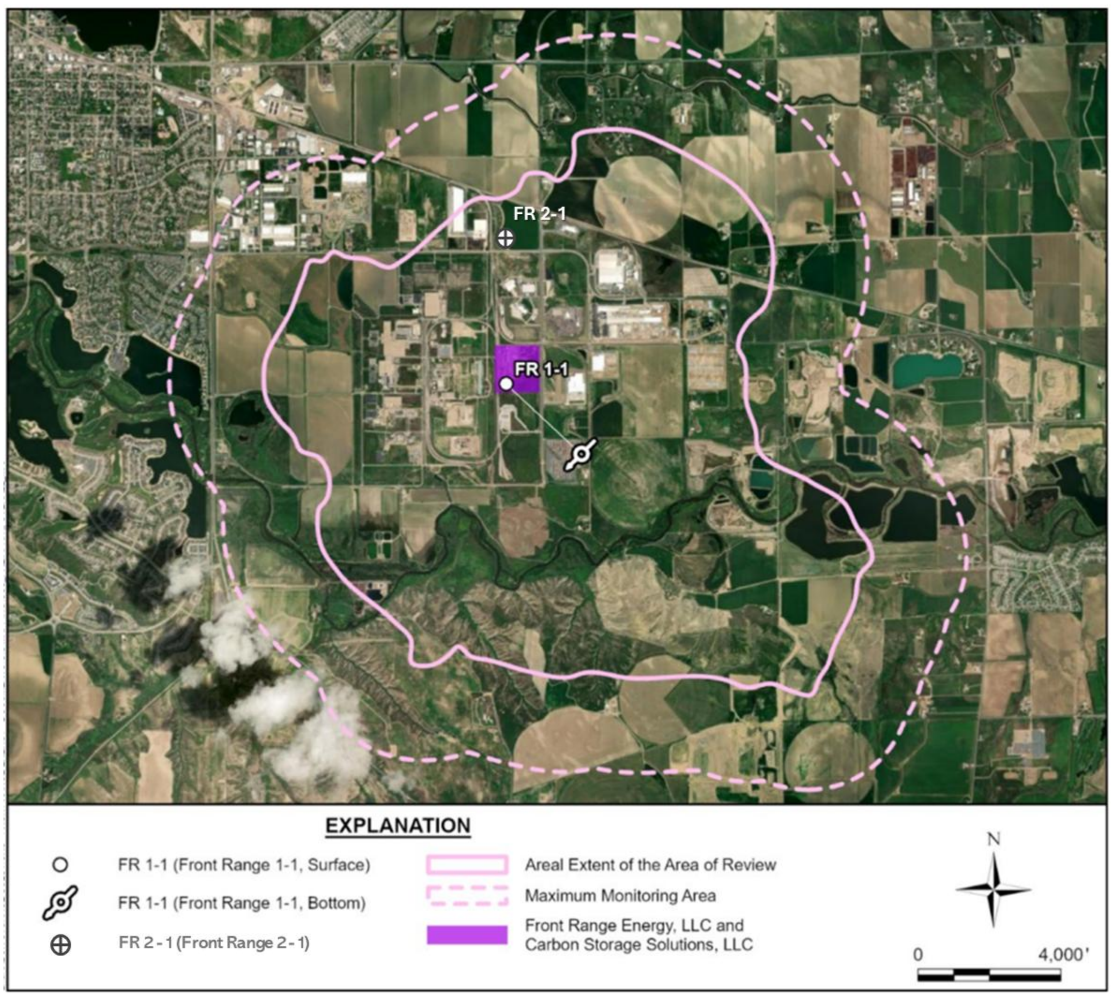
1.0 Introduction

The well construction details for the FR 1-1 injection and FR 2-1 monitoring wells are described in this attachment and include construction requirements, injection intervals, casing, tubing, packer and cement specifications. The design parameters and materials selection are to ensure sufficient structural strength and mechanical integrity for the life of the Project.

2.0 Injection Well Design

Front Range 1-1 is a directionally drilled well whose surface and bottomhole locations are shown in Figure 1.

Figure 1: Surface and Bottomhole Location of Front Range 1-1



The well design includes three casing sections in addition to the conductor casing: 1) surface casing to protect shallow USDW while drilling to the injection zone, 2) intermediate section, and 3) a long string section from the injection zone to the surface. Figure 2 presents the directional wellbore schematic. Figure 3 shows the wellbore construction schematic in detail without deviation.

Figure 2: Directional Wellbore Schematic for Front Range 1-1

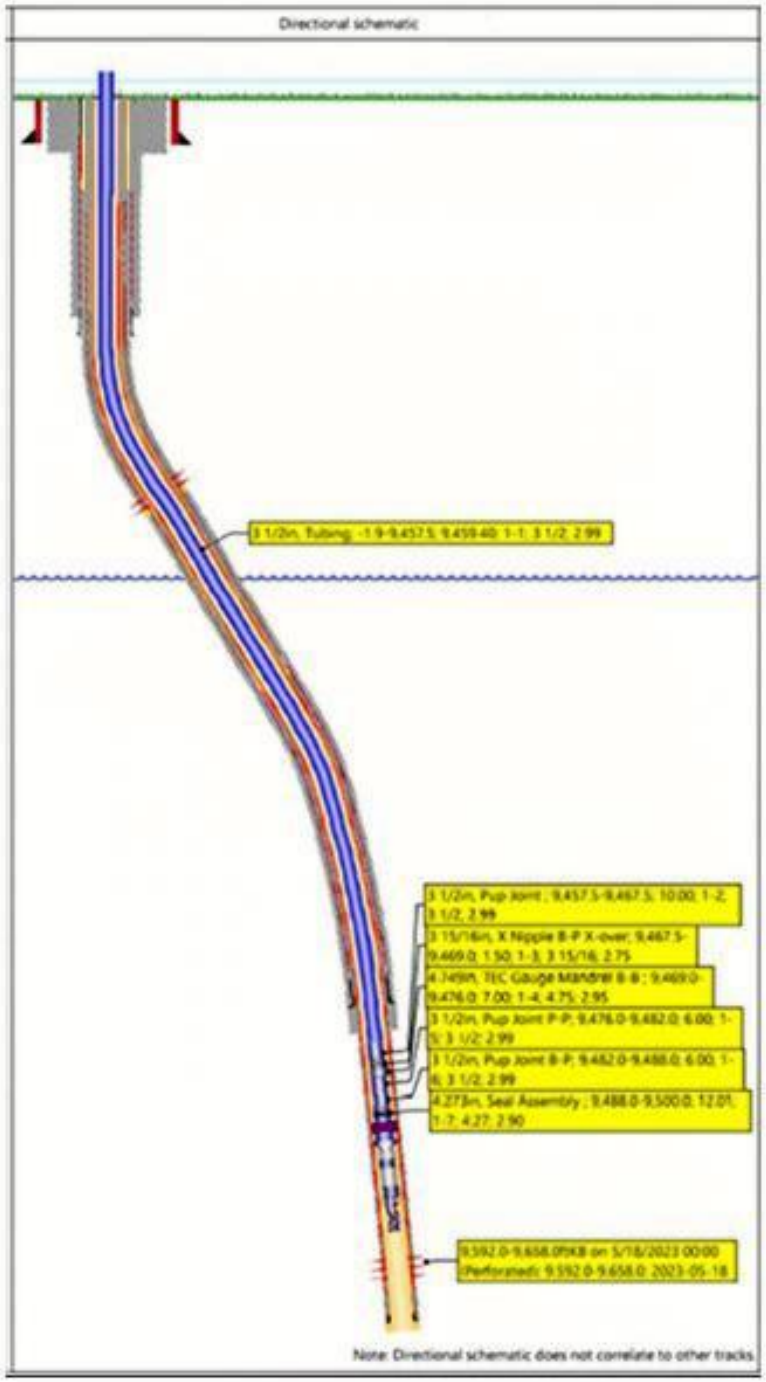
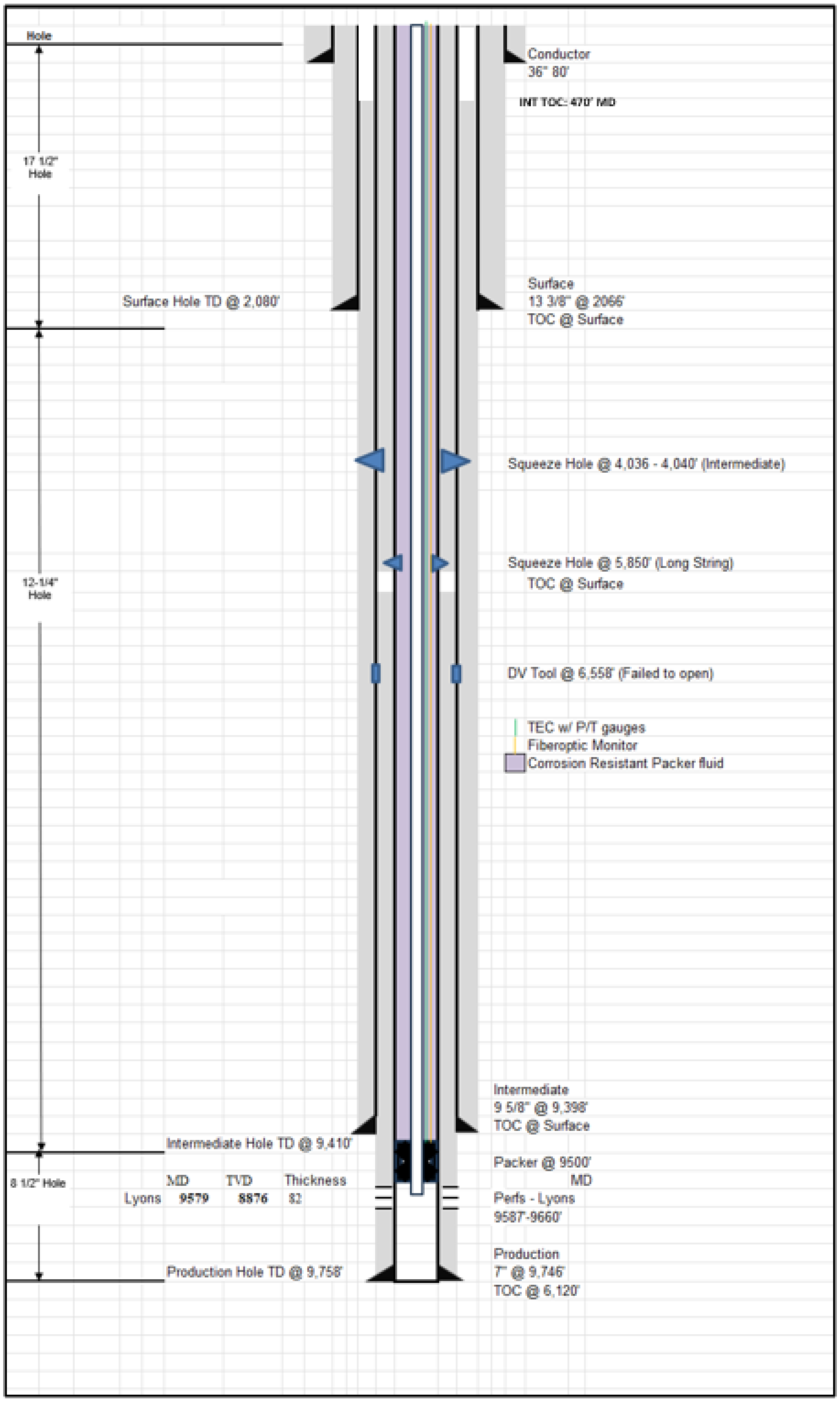


Figure 3: Wellbore Construction Schematic for Front Range 1-1 (Deviation not shown).



Details of well design are provided in the following tables. Table 1 contains the open hole diameters of each section, Table 2 lists the casing specifications, and Table 3 details the casing material properties. In addition, Table 4 contains the tubing and safety valve specifications, and Table 5 shows the packer material properties.

Table 1: Open Hole Diameters and Intervals

Open Holes	Depth Interval (ft)	Open Hole Diameter (inches)
Conductor	80	36
Surface	2,080	17 1/2
Intermediate String	9,410	12 1/4
Long String	9,758	8 1/2

Table 2: Casing Specifications

String	Depth Interval (ft)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Coupling	Burst Rating (psig)	Collapse Resistance (psig)
Conductor	80	20	19.5	52.78	A53B	NA	NA	NA
Surface	2066	13 3/8	12.615	54.5	J-55	BTC	2,730	1,130
Intermediate String	9398	9 5/8	8,835	40	HCL-80	BTC	5,750	4,230
Long String	9,746	7	6.184	29	13CR-80	VAM TOP	8,160	7030

ft = feet
lb/ft = pounds per foot
psig = pound-force per square inch, gauge
13 Chrome (CG) 80
NA = not applicable

Table 3: Casing Material Properties

Casing	Weight (lb/ft)	Grade (API)	Coupling	Joint Yield Strength (Lbs)	Body Yield Strength (Lbs)
Conductor	52.78	A53B	STC	60,000	35,000
Surface	54.5	J-55	BTC	909,000	853,000
Intermediate String	40	HCL-80	BTC	837,00	916,000
Long String	29	13CR-80	VAM TOP	676,000	676,000

Table 4: Tubing and Subsurface Safety Valve Specifications

Name	Depth Interval (ft)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Coupling	Burst Strength (psig)	Collapse Strength (psig)
Tubing	0 – 8,758	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
Sliding Sleeve	8,758 -8,761	2.875	2.31	NA	L-80	EUE	10,400.00	8,946.00
Tubing	8,761 – 9,381	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,831 – 9,832	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
7" AHR Packer	9,382 -9,386	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,386 – 9,454	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160
Sliding Sleeve	9,454 – 9,458	2.875	2.31	NA	INC 925	EUE	14,300.00	12,300.00
Tubing	9,458 – 9,577	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160.00
X Nipple	9,577 – 9,558	2.875	2.31	NA	Inc 925	EUE	14,530.00	14,550.00
7" AHR Packer	9,558 – 9,563	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,563 – 9,569	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,569 – 9,570	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
Tubing	9,570 – 9,576	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
XN Nipple	9,576 – 9,577	2.875	2.21	NA	L-80	EUE	10,570.00	11,170.00

Table 5: Packer Material Properties

Packer								Casing Interface		
Type and Material	Setting Depth (ft)	Length (ft)	Outer Diameter Inches	Inner Diameter (inches)	Tensile Rating (Lbs)	Burst Rating (psig)	Collapse Rating (psig)	Nominal Weight (lb)	Max Inner Diameter (inches)	Min Inner Diameter (inches)
Permanent Nickel Alloy 925	9,500	4	5,875	4	232,800	10,410	9,940	NA	4	2.5

The annulus space between the long string casing and injection tubing must be filled with fluid.

The completion fluid must be treated with a corrosion inhibitor that is compatible with the wellbore environment and bottomhole temperatures to prevent the internal corrosion of the long string casing and the external corrosion of the injection tubing.

3.0 Injection Well Cement Requirements and Details

The Permittee must ensure that the surface casing extends to the base of the lowermost USDW and is cemented to surface, consistent with 40 CFR 146.86(b)(2). All cement utilized in the well construction is corrosion resistant cement for use in CO_2 projects, as shown in Table 6.

This was accomplished by multiple strings of casing (surface and intermediate) and cement.

Table 6: Cement used during Front Range 1-1 Construction

Surface Section

Cement Type	Depth Interval (ft)	Description
Class G Cement	0 to 2,043	Cemented to surface, standard cement selection for contact with formation fluids

Intermediate Section

First Stage – 9,375 ft MD

Cement Type	Depth Interval (ft)	Description
Litepoz 3 (Lead Slurry)	2,043 to 9,375	Density of 13.5 ppg, yield of 1.64 ft^3/sk
EverCRETE (Tail Slurry)	9,375 to 9,387	Density of 14.8 ppg, yield of 1.21 ft^3/sk

Second Stage – Perforations at 4,040 ft MD

Cement Type	Depth Interval (ft)	Description
Litepoz 3 (Lead Slurry)	470 – 4,040	Density of 12 ppg, yield of 1.8 ft^3/sk
CemFIT Heal (Tail Slurry)	470 – 4,040	Density of 13.5 ppg, yield of 1.64 ft^3/sk

Production Section – 9,746 ft MD

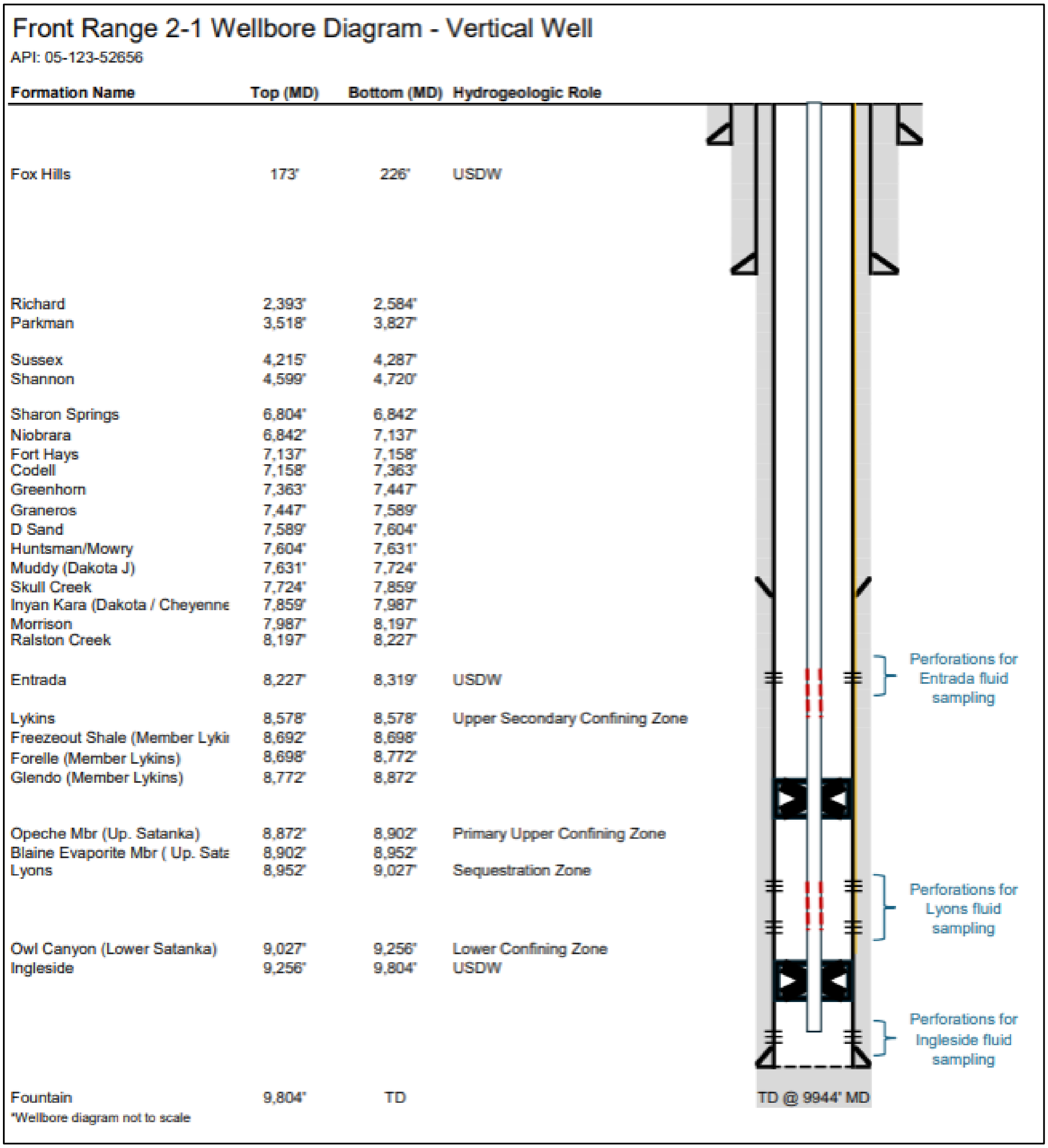
Cement Type	Description
CemFIT Heal Slurry	Lead cement with a density of 12.0 ppg and a yield of 1.80 ft3/sk
MidLead Slurry	Intermediate cement with a density of 12.0 ppg and a yield of 2.01 ft3/sk
EverCRETE Slurry	Tail cement with a density of 14.80 ppg and a yield of 2.01 ft3/sk, recommended for CO2 resistance

The Permittee must ensure that there is at least one long string casing, using a sufficient number of centralizers, that extends to the injection zone and must be cemented by circulating cement to the surface.

<u>8.0</u> <u>Monitoring Well Design</u>

Front Range 2-1 is a vertically drilled well whose surface hole locations are shown in Attachment B, Figure 1. The well design includes three casing sections in addition to the conductor casing: 1) surface casing to protect shallow USDW while drilling to the injection zone, 2) intermediate section, and 3) a long string section from the injection zone to the surface. Figure 4 shows the wellbore construction schematic in detail.

Figure 4: Wellbore Schematic for Front Range 2-1



Details of well design are provided in the following tables. Table 7 contains the open hole diameters of each section, Table 8 lists the casing specifications, and Table 9 details the casing material properties. In addition, Table 10 contains the tubing and safety valve specifications, and Table 11 shows the packer material properties.

Table 7: Open Hole Diameters and Intervals

Open Holes	Depth Interval	Open Hole Diameter

	[ft]	[inches]
Conductor	80	26
Surface	2,010	13 1/2
1/2	9,390	8 1/2

Table 8: Casing Specifications

String	Depth Interval (ft)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Coupling	Burst Rating (psig)	Collapse Resistance (psig)	Tensile Strength (Lbs)
Conductor	0-80	16	15.01	84	J-55	EUE	2,980	1,410	1,326,000
Surface	0 – 2010	10 3/4	10.05	40.5	J-55	Butress Thread	3,130	1,580	629,000
Long String	0 – 6,700	7	6.18	29	HCL-80	Buttress Thread	8,160	7,020	676,000
Long String	6,700 – 9,390	7	6.18	29	13-CR80	Vallourec VAM	8,160	7,020	676,000

Table 9: Casing Material Properties

Casing	Weight (lb/ft)	Grade (API)	Coupling	Joint Strength (Lbs)	Yield Strength (Lbs)
Conductor	84	J-55	EUE	817,00	1,326,000
Surface	10-3/4	J-55	Butress	420,00	629,000
Long String	7	HCL-80	Butress	780,000	676,000
Long String	7	13-CR80	VAM	676,000	676,000

Table 10: Tubing and Subsurface Safety Valve Specifications

Name	Depth Interval (ft)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Coupling	Burst Strength (psig)	Collapse Strength (psig)
Tubing	0 – 8,758	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
Sliding Sleeve	8,758 - 8,761	2.875	2.31	NA	L-80	EUE	10,400.00	8,946.00
Tubing	8,761 – 9,381	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,831 – 9,832	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
7" AHR Packer	9,382 - 9,386	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,386 – 9,454	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160
Sliding Sleeve	9,454 – 9,458	2.875	2.31	NA	INC 925	EUE	14,300.00	12,300.00
Tubing	9,458 – 9,577	2.875	2.44	6.50	13-CR80	EUE	10,570.00	11,160.00
X Nipple	9,577 – 9,558	2.875	2.31	NA	Inc 925	EUE	14,530.00	14,550.00
7" AHR Packer	9,558 – 9,563	6.13	2.38	NA	INC 925	EUE	8,710.00	8,400.00
Tubing	9,563 – 9,569	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
X Nipple	9,569 – 9,570	2.875	2.31	NA	L-80	EUE	10,570.00	11,170.00
Tubing	9,570 – 9,576	2.875	2.44	6.50	L-80	EUE	10,570.00	11,160.00
XN Nipple	9,576 – 9,577	2.875	2.21	NA	L-80	EUE	10,570.00	11,170.00

Table 11: Packer Material Properties

Packer								Casing Interface		
Type and Material	Setting Depth (ft)	Length (ft)	Outer Diameter (Inches)	Inner Diameter (inches)	Tensile Rating (Lbs)	Burst Rating (psig)	Collapse Rating (psig)	Nominal Weight (lb)	Max Inner Diameter (inches)	Min Inner Diameter (inches)
Hydraulic Set Perma-Latch Packer -Inc 925	8,896 – 8,901	5	6.013	2.38	145,000	8,710	8,400	NA	6.0	2.377
Hydraulic Set Perma-Latch Packer -Inc 925	9,063 – 9,068	5	6,013	2.38	145,000	8,710	8,400	NA	6.0	2.377

The annulus space between the long string casing and injection tubing must be filled with fluid.

The completion fluid must be treated with a corrosion inhibitor that is compatible with the wellbore environment and bottomhole temperatures to prevent the internal corrosion of the long string casing and the external corrosion of the injection tubing.

5.0 Monitoring Well Cement Requirements and Details

The Permittee must ensure that the surface casing extends to the base of the lowermost USDW and is cemented to surface, consistent with 40 CFR 146.86(b)(2). All cement utilized in the well construction is corrosion resistant cement for using in CO_2 projects, as shown in Table 12.

This was accomplished by multiple strings of casing (surface and intermediate) and cement.

Table 12: Cement used during Front Range 2-1 Construction by Section

String	Depth Interval	Cement Type
Conductor Casing	Surface – 80 ft	Class G
Surface Casing	Surface – 2,000 ft	Class G
Long String (Upper Stage)	Surface - 8,319 ft	VersaCem
Long String (Lower Stage)	8,319 - 9,380 ft	CorrosaLock

ATTACHMENT H: FINANCIAL RESPONSIBILITY DEMONSTRATION

1.0 Financial Assurance

The Permittee must demonstrate and maintain financial responsibility, and the demonstration must be approved by the Director pursuant to 40 CFR 146.85. The Director may disapprove the use of a financial instrument if it is determined to be insufficient to meet financial assurance requirements. The Permittee must provide any updated information related to their financial responsibility instrument(s) on an annual basis according to Section G of this Permit.

Financial instrument(s) must be from the following list of qualifying instruments:

- Trust Funds
- Surety Bonds
- Letters of Credit
- Insurance
- Self-Insurance (i.e. Financial Test and Corporate Guarantee)
- Escrow Account
- Any other instrument(s) satisfactory to the Director

The Permittee may demonstrate financial responsibility by using one or multiple qualifying instruments for specific phases of the Project in accordance with 40 CFR 146.85(a)(6)(i)-(vii). The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.

The financial responsibility instruments must be sufficient to address endangerment of underground sources of drinking water (USDWs) and comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass bond rating when applicable.

When Self Insurance (i.e., Financial Test and Corporate Guarantee) is used as the financial mechanism, the Permittee must update such coverage on an annual basis.

2.0 Activities Requiring Financial Assurance

Pursuant to 40 CFR 146.85, the Permittee is required to demonstrate financial ability to successfully complete all the tasks associated with performing corrective action, plugging injection and monitoring wells, post-injection site care, site closure, and implementation of an emergency remedial response. The estimated costs of these activities, as provided by Permittee and approved by the Director, are presented in Table 1.

Table 1: Cost Estimates for Activities to Be Covered by Financial Responsibility.

Activity	Cost (million $US)	Instrument
Corrective action	Not Applicable	Not Applicable
Plugging injection well	Front Range 1-1: $456,000 Front Range 2-1: $342,000	Surety Bond
Post-injection site care	$6,000,000	Surety Bond
Site closure	$290,000	Surety Bond
Emergency and remedial response	$15,000,000	Third Party Insurance

If needed, the cost estimates will be reevaluated prior to the commencement of injection operations.

3.0 Activities Covered by Financial Responsibility

3.1 *Plugging Injection Wells*

The Well Plugging Plan is found in Attachment D of this Permit.

3.2 *Post-Injection Site Care and Site Closure*

Details of the Post-Injection Site Care and Site Closure Plan are found in Attachment E of this Permit. Post-injection site care costs were estimated from cessation of injection to site closure and account for seismic studies at five-year intervals, maintenance of the wells until closure, and monitoring the site to ensure protection of USDWs. Site closure costs include plugging monitoring wells, removal of surface facilities, and reclamation of the site.

3.3 *Emergency and Remedial Response*

The Emergency and Remedial Response Plan is found in Attachment F of this Permit.

ATTACHMENT I: QUALITY ASSURANCE AND SURVEILLANCE PLAN

The Permittee must adhere to the Quality Assurance and Surveillance Plan (QASP) submitted as part of the permit application. The QASP establishes the quality assurance and quality control (QA/QC) procedures applicable to all sampling, testing, monitoring, laboratory analysis, data management, and reporting activities conducted to demonstrate compliance with the requirements of the Underground Injection Control (UIC) Class VI program under 40 CFR Part 146.90(k).

The QASP specifies the procedures and standards necessary to ensure that all data generated for the project are of known and documented quality and are suitable for regulatory compliance determinations. The plan includes requirements for standard operating procedures, instrument calibration and maintenance, analytical methods, chain-of-custody procedures, data verification and validation, and corrective actions.

The Permittee must conduct all monitoring, sampling, testing, and reporting activities associated with the pre-injection, injection, and post-injection site care periods in accordance with the approved QASP. Any material modifications to the QASP must be approved by the Director prior to implementation.