Underground Injection Control

Fact Sheet for Class VI Draft Permit

CO62455-12770

Front Range 1-1

March 2026

Carbon Storage Solutions Front Range Geologic Sequestration Project

Facility Information

Permittee: Carbon Storage Solutions, LLC

Facility name: Front Range Storage Complex

Well Name: Front Range 1-1

Well Class: VI – Geologic Sequestration

Well location: Weld County, Colorado

Surface Township, Range, Section: T6N, R67W, Section 26, 6th PM

Bottomhole Township, Range, Section: T6N, R67W, Section 35, 6th PM

Surface Latitude: 40.454962 **Longitude**: -104.859761

Bottomhole Latitude: 40.449494 **Longitude**: -104.852200

Part I: Overview

Introduction

The Environmental Protection Agency (EPA) Region 8 is accepting comments from the public on its intent to issue a permit for Carbon Storage Solutions, LLC (CSS) to inject carbon dioxide (CO_2) underground at its proposed Front Range injection well near the Town of Windsor in Weld County, Colorado. This injection would be part of a process that is often called “geologic sequestration” or “carbon sequestration.” Carbon sequestration is a means of reducing emissions of CO_2 released into the atmosphere. All public comments must be submitted through regulations.gov Docket # EPA-R8-OW-2026-1915 by April 8, 2026. In issuing a permit for a geologic sequestration project, the EPA has authority to protect underground sources of drinking water (USDW). Other federal, state, and local agencies may have authorities relevant to surface activities such as carbon capture and transportation, and to address protection of other resources such as surface water and air quality.

Carbon Storage Solutions constructed an injection well at the Front Range Energy ethanol production facility for the purpose of injecting CO_2 captured from the production process to a depth of 8,876 feet (ft) underground for long-term storage (Figure 1). The proposed project will have one deep monitoring well completed in the injection zone, nine shallow monitoring wells completed in near-surface aquifers, and soil gas monitoring stations in the project area of review (AoR). The draft permit allows CSS to inject up to 127,800 metric tons of CO_2 per year into this well for a total project volume of up to 1.54 million metric tons, which is projected to be completed in 12 years. The injection fluid must consist of at least 99 percent pure CO_2.

The EPA is proposing to issue a permit to CSS after reviewing extensive information about the project site. This technical evaluation by the EPA helps ensure that the well is placed at a site where the geology is suitable, the CO_2 can be securely stored underground, and the well will operate safely. The rock formation where the CO_2 will be stored is about 1.7 miles below ground, and site-specific data show that approximately 600 ft of shale, silty sandstone, carbonate, and anhydrite provide confinement and prevent fluid movement between the proposed injection zone and the deepest USDW that overlies the injection zone. It is important to note that the EPA's permitting decision must be based on the underlying geology and protection of USDWs.

Pursuant to the draft permit, CSS must monitor all facets of the sequestration project including but not limited to condition of the injection well, the injection pressure, and the location and size of the injected CO_2 plume during the 12 years of proposed CO_2 injection and for 20 years after injection is finished, which is the proposed alternate post-injection site care (PISC) period. These monitoring requirements are to 1) ensure the injection well operates properly, 2) determine if any changes in operation are needed to protect USDWs, 3) observe how the movement of the CO_2 compares to modeled outcomes (both during and after injection), and 4) confirm that it is safe to close the project site at the end of the PISC period.

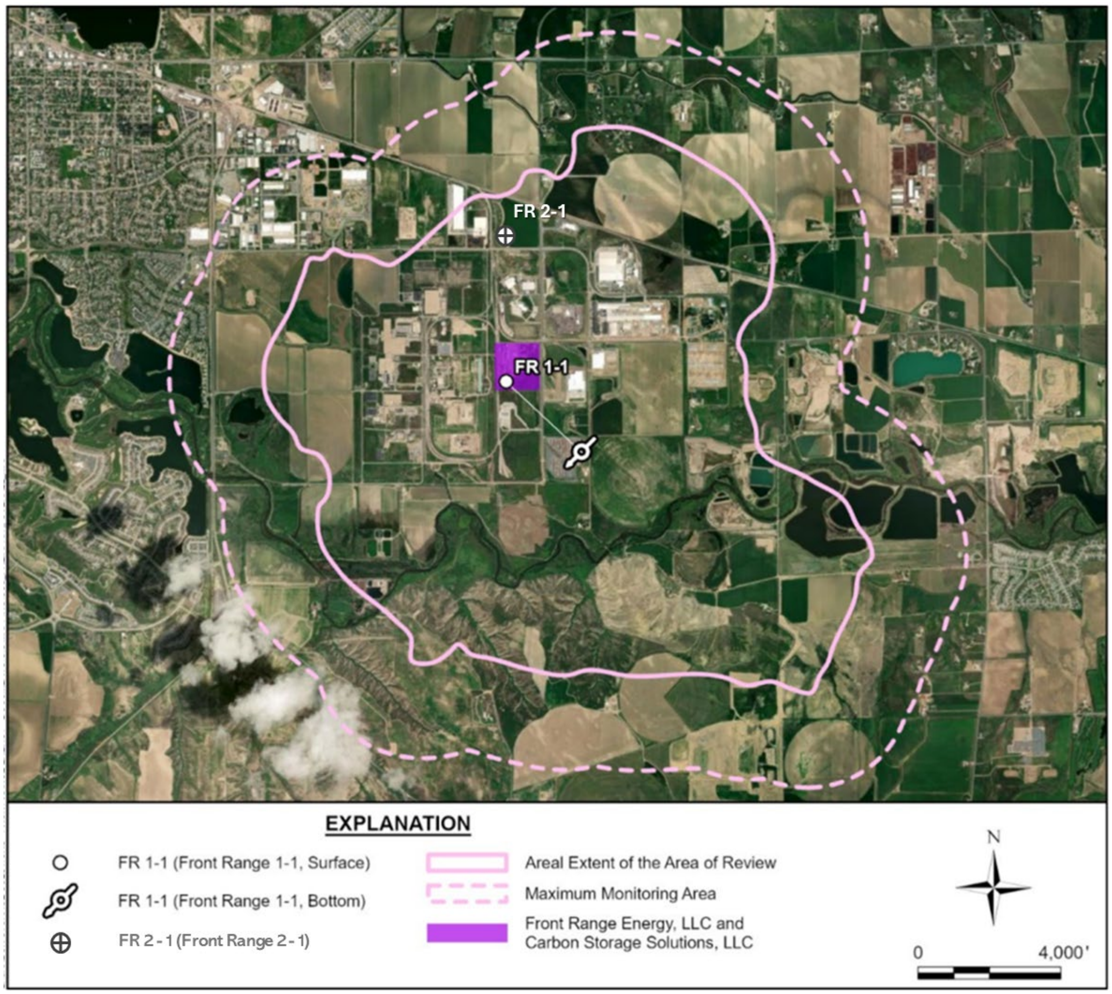


Figure 1. Area of review for the Front Range 1-1 injection well, delineated by reservior modeling with site-specific and regional data.

Options for Participating in the Permitting Process
and
Procedures for reaching a final decision (40 CFR 124.8(b)(6))

The EPA will accept written comments on the proposed permitting decision. You can submit a public comment on the draft permit at Regulations.gov. The comment period begins March 9, 2026, and ends April 8, 2026.

A public hearing will be held upon request. To request a hearing, contact Zac Moore by email at moore.zac@epa.gov, or by phone at 1-800-227-8917 ext. 312-7075 or (303) 312-7075. Hearing requests must be received by April 8, 2026. If a public hearing is held, EPA Region 8 will publicly notice the time and location. If a public hearing is held, the EPA will record or accept oral comments.

You must send written comments on the draft permit decision or participate in a public hearing (if held) to preserve your right to appeal a final permitting decision.

Contact Zac Moore at 303-312-7075 or moore.zac@epa.gov for additional information pursuant to 40 CFR 124.8(7).

More information about the Front Range Storage Complex can be found on the company's website at www.frontrangeenergy.com/Carbon-Storage-Solutions

How did the EPA make its tentative decision?

To reach a tentative decision and prepare the draft permit, the EPA reviewed the project-specific technical, scientific, and financial information submitted by CSS in their permit application materials. Where appropriate, the EPA also consulted other information sources to conduct a rigorous evaluation of the application materials and the suitability of the project site. The goal of the EPA's review and tentative determination is to ensure that the project will be protective of USDWs.

The Front Range geologic sequestration project is specifically engineered to ensure the safe and secure sequestration of CO_2 from ethanol production. Comprehensive site characterization was conducted to assess the geology and hydrogeology of the injection site. This involved evaluating the confining zones formation integrity and the reservoir's capacity to securely contain CO_2. The project demonstrated through logs, geophysical studies, and computational modeling that the CO_2 will remain confined within the designated geological formation and that there is no risk of migration into USDWs.

Advanced monitoring systems will be employed to track the movement of CO_2 in the subsurface and detect any potential leaks or pressure changes. These systems will provide real-time data to ensure that emergency response and remediation can be swiftly implemented for the protection of USDWs. If monitoring data indicate plume movement inconsistent with the computational modeling, the AoR must be re-evaluated.

A non-exhaustive, general overview of the types of data and information the EPA reviewed for the key permit conditions and the key regulatory requirements are described briefly below in Part 2 of this document. The memorandums in the administrative record present the more technical project-specific details on each of these topics and are referenced below where appropriate.

What happens next in the permit process?

The EPA will review all public comments received during the public comment period before making a final decision on whether to issue the permit. The EPA will respond to all significant comments on the draft permit. This is the public's only opportunity to provide comments on the draft permit. If the EPA decides to issue final permit, there will not be an additional opportunity to comment on the final permit, although the final permit may be appealed by any person who commented on the draft permit.

If the EPA's final decision is to issue final permit, CSS would be authorized to construct the well. However, CSS would not be authorized to inject until it has complied with specific permit requirements including all pre-operational testing in Section I of the draft permit. The EPA will review the information submitted by the Permittee following all required tests to determine whether all the required elements of Section J have been met prior to issuance of a written authorization to inject.

Part 2: Technical Background, Front Range Storage Complex Information, and Permit Conditions

The EPA conducted a thorough review of CSS's permit application and other relevant information during evaluation of this permitting decision. The data and information are publicly available as part of the administrative record for the draft permit. Title 40 of the Code of Federal Regulations (CFR) Parts 144 and 146 require EPA permits for CO_2 storage, known as UIC Class VI permits, to specify conditions for the siting, construction, operation, monitoring, reporting, plugging, post-injection and site closure of Class VI injection wells to prevent the movement of fluids into any USDWs. See 40 CFR Parts 144 and 146 for the general provisions of underground injection permits.

This part of the draft permit fact sheet provides: (1) references to the primary applicable statutory or regulatory provisions for each portion of the permit, (2) a brief summary of the key draft permit conditions, and (3) a brief summary of the basis for those conditions, including the technical background and information on the Front Range project and appropriate supporting references to the administrative record, to help the public better understand how the EPA reached the proposed permitting decision. See 40 CFR 124.8(b)(4). Within these sections, the principal facts and the significant factual, legal, methodological and policy questions considered in preparing the draft permit are discussed as appropriate. See 40 CFR 124.8(a).

The EPA's review of CSS's permit application and other information in the record indicates that a permit with appropriate conditions will prevent endangerment of USDWs. In accordance with the UIC permit fact sheet requirements at 40 CFR 124.8, information and related permit conditions for the proposed well are presented below.

Site Characterization and Siting, including Geology and Hydrogeology of the Injection Zone(s) and Confining zones(s)

Federal Requirements under the Class VI Rule

Applicants must submit extensive geologic, hydrogeologic, and hydrologic information, which is described at 40 CFR 146.82. Requirements under 40 CFR 146.83 define the minimum geologic siting criteria for a Class VI injection well, including an injection zone that will receive the CO_2 stream and confining zones that will contain the injected CO_2.

Some of the specific types of information required to be submitted by the applicant and reviewed by the EPA include the geologic structure and hydrogeology of the project site and data on the properties of the rocks in the injection and confining zones. This information, along with the faults, fractures, and seismicity information described below, is used to confirm that the CO_2 will remain in the injection formation after it is injected, i.e., that there are no faults, fractures, or other pathways that will allow for CO_2 to move out of the injection zone, and that there is also a thick, dense, impermeable formation above and below the injection formation that will serve as "confining zones," preventing movement of the CO_2 out of the injection formation.

Draft Permit Conditions

Injection for geologic sequestration is limited to the injection zone, the Lyons Sandstone Formation, which occurs between the depths of 8,876 and 8,958 ft below ground surface. A water sample collected from the Lyons at the Front Range 1-1 well exhibited a TDS concentration of 34,076 mg/L, indicating it is not a USDW, which is consistent with regulatory requirements for Class VI injection. The confining zone immediately above the injection zone is the Lykins Formation from a depth of 8,268 to 8,876 ft below ground surface, and it is free of known transmissive faults or fractures within the AoR. The confining zone immediately below the injection zone is the Lower Satanka (Owl Canyon) Formation from a depth of 8,958 to about 9,189 ft below ground surface, which also is free of known transmissive faults or fractures within the AoR. The EPA considered the geologic characteristics of and relationships between the injection zone, confining zones, and USDWs within the AoR to determine the suitability of the geologic setting for injection, long term containment, and isolation of injected fluids from USDWs.

For details on the permit conditions related to site geology and hydrology, see Attachment B in the draft permit.

Application Review and Decision Process

The EPA reviewed information about the regional geology (rock layers and structures), information and data related to the site geology, hydrogeology, and hydrology, the applicant's detailed study of the geology at the project site, and other relevant information to ensure it complies with all requirements. This included topographic and geologic maps, cross sections, well logs, core and core analysis, seismic data, historic seismicity, water quality samples, and regional data.

Injection Zone: Lyons Sandstone

The Lyons Sandstone is the target injection interval for the Front Range 1-1, located at a depth of 8,876 ft below ground surface, and is 82 ft thick. It is characterized by porosity ranging from 3 to 15% with a mean of 7.8% and permeability ranging from 0.12 to 19.3 millidarcy (mD) with a mean of 3.3 mD. The Lyons Sandstone was modeled as a sandstone with variation in cementation impacting porosity and permeability. Laboratory analysis of a sample collected from the Lyons Formation at the Front Range 1-1 injection well indicated a TDS concentration of 34,076 mg/L. Based on 176 TDS values for the Lyons Formation at wells surrounding the Front Range 1-1, the average TDS concentration of the Lyons is 38,105 mg/L, which differs from the Front Range 1-1 value by about 11%.

The Lyons Formation has historically been used as a zone for the Class II disposal of fluids associated with oil and gas production in the Denver-Julesburg Basin of Colorado and Wyoming. The reservior characteristics include abnormally low pressure, high porosity, and good permeability, which provide an excellent storage formation. Cross sections, maps, and seismic surveys show that the reservior is laterally extensive and the closest outcrop is 17 miles to the west.

Upper Confining zone: Lykins Formation

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.

Opeche Shale: This unit is characterized by predominantly brownish-red claystone with interbeds of gypsum, sandstone, and sandy shales. It is 29 ft thick at the Front Range 1-1 well, with 95% of the formation consisting of shale that exhibits a clay content of approximately 64.1%. The remaining 5% is composed of thin intervals of dolomite, anhydrite, and siltstone.

Blaine Evaporite: The Blaine Evaporite is composed of thick beds of gypsum/anhydrite, alternating with beds of shale and thin dolostones. At the Front Range 1-1 well, the Blaine is 55 ft thick, with 48 ft (88%) composed of anhydrite. The remaining 7 ft contains thin mudstone/shale, siltstones, and dolomite. Porosity measured in samples from the Blaine ranged from 0.67% to 3.2%, with permeability values indicating a very effective seal for sequestration. The confining layers have an average porosity of less than 5 percent and permeability averaging less than 0.3 mD.

Lower Confining Zone: Lower Satanka (Owl Canyon) Formation

The Lower Satanka Formation, also referred to as Owl Canyon Formation, is the underlying confining unit beneath the Lyons Sandstone. The thickness of the Lower Satanka Group was not fully penetrated by the

Front Range 1-1 well, therefore the exact thickness at the formation is unknown, however it was estimated from the Front Range 2-1 that was drilled to the Ingleside Formation. Data from the Front Range 2-1 indicates that the Lower Satanka is approximately 231 ft thick near the site. Based on testing of core specimens collected in the upper 50 ft of the formation, the Lower Satanka has a porosity of 2.8 % and permeability of 0.0002 mD, contributing to its role as a confining layer.

The upper and lower confining zone consist of thick (greater than 50 ft) and low permeability, tight shales with high clay percentages and impermeable evaporites. These characteristics are indicative of the sealing capabilities of the confining zone, which would prevent movement of fluids out of the injection zone.

Based on the review of the information provided by CSS and additional information, the EPA determined the proposed Front Range Storage Complex meets the requirements for the injection and confining zones, thereby protecting USDWs from endangerment, as required under 40 CFR 146.83. See the relevant permit application documents and other supporting materials as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Fault Stability Analysis, Fault Sealing Analysis, Fractures, and Seismicity

Federal Requirements under the Class VI Rule

The Class VI Rule requires the injection well to be sited where the geologic system can receive and contain the CO_2 (40 CFR 146.83). In particular, the owner or operator must demonstrate that the confining zones are free of faults or fractures that could allow fluid movement and that the authorized injection zone can contain the CO_2 (40 CFR 146.83(a)(2). The Class VI Rule, at 40 CFR 146.82(a)(3)(ii) requires owners or operators to submit information regarding any faults or factures that may transect the confining zones in the AoR and for the EPA to consider whether any such faults or fractures will interfere with containment. This determination is made after analysis of fault stability and whether there is a risk of natural or induced (injection-related) seismicity at the project site (40 CFR 146.82(a)(3)(v)).

Draft Permit Conditions

After a thorough review of faults, fractures, and the potential for induced seismicity within the AoR, the EPA has determined that the Front Range Storage Complex does not present any structural or geomechanical concerns. While no data indicate a fault hazard in the AoR, CSS is required to monitor the U.S. Geological Survey (USGS) earthquake network as part of the testing and monitoring plan. CSS is required to subscribe to notifications from the USGS Notification Service for all seismic events within 100 km of the injection well. If a seismic event with a moment magnitude greater than 3.5 occurs within 100 km of the injection well, CSS will be required to initiate shutdown, notify the EPA, and monitor the well pressure, temperature, and annulus pressure of the injection well to verify well status and determine the extent of any failure. If there has been a failure of monitoring equipment or a loss of mechanical integrity, CSS must implement the response actions listed in Attachment F of the draft permit.

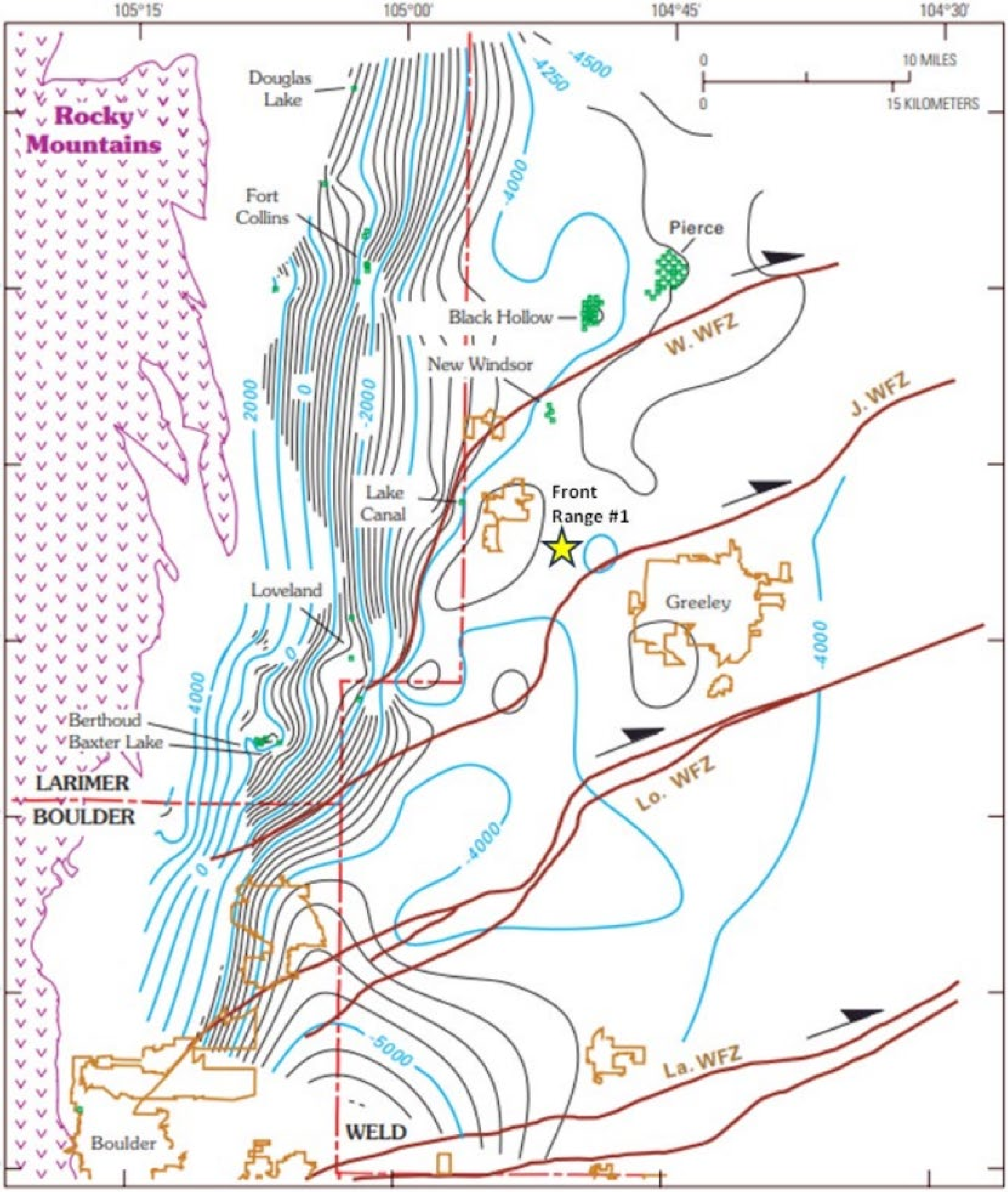
Application Review and Decision Process

The EPA reviewed information in the permit application related to fault identification in the AoR, fractures identification, regional historic seismicity and other relevant information to determine if the project site meets Class VI requirements regarding containment and any potential risks from faults or fractures.

Evaluation of faults, fractures, and seismic activity in the region of the Front Range 1-1 well location shows no fluid migration pathways from the injection zone to USDWs.

a. Faults

The site is situated in the Denver-Julesburg Basin, which is characterized by a strike-slip stress regime, as discussed by Lund Snee and Zoback (2022) in their study on the state of stress in areas of active unconventional oil and gas development in North America (AAPG Bulletin, 106(2): 335–385). The project location lies between the Windsor Fault system and the Johnstown Fault system, both of which are vertical, right-lateral wrench faults (Figure 2) formed during the Laramide orogeny. These faults extend from the Precambrian crystalline basement to the Cretaceous Muddy J Sandstone, as detailed by Higley and Cox (2005) in their US Geological Survey Professional Paper on oil and gas exploration along the Front Range in the Denver Basin of Colorado, Nebraska, and Wyoming. Although stress states and faulting are complex, further evidence discussed later in this section suggests that the likelihood of large fluid migration pathways existing within the AoR is minimal.



Modified from: Higley, D.K., & Cox, D.O. (2005)

Figure 2. Map Showing Location of Wrench Faults in the Denver Basin. Labeled wrench faults at Windsor (W. WFZ), Johnstown (J. WFZ), Longmont (Lo. WFZ), and Lafayette (La. WFZ) arrows indicate direction of lateral movement. (CSS, 2024)

Figure 3 shows a composite 2D line constructed from a 3D seismic volume around the location of the Front Range 1-1 well. Continuity of seismic reflectors shows no large structures or faulting around the wellbore. On the lower right side of the diagram, there is a noticeable structure labeled fold, which is approximately 4 miles south of the project area. This is a shallow representation of faulting at depth. This fault extends into the basement, interpreted to begin around 1.8mS Two-Way Time. The resolution quality of Amoco 2D Line 70PAN-CO-HK-25 is moderate. The fault is interpreted to terminate below the injection zone, as reflectors above are folded and no offset is apparent. This indicates that the fault movement occurred prior to the deposition of the confining layers and injection zone.

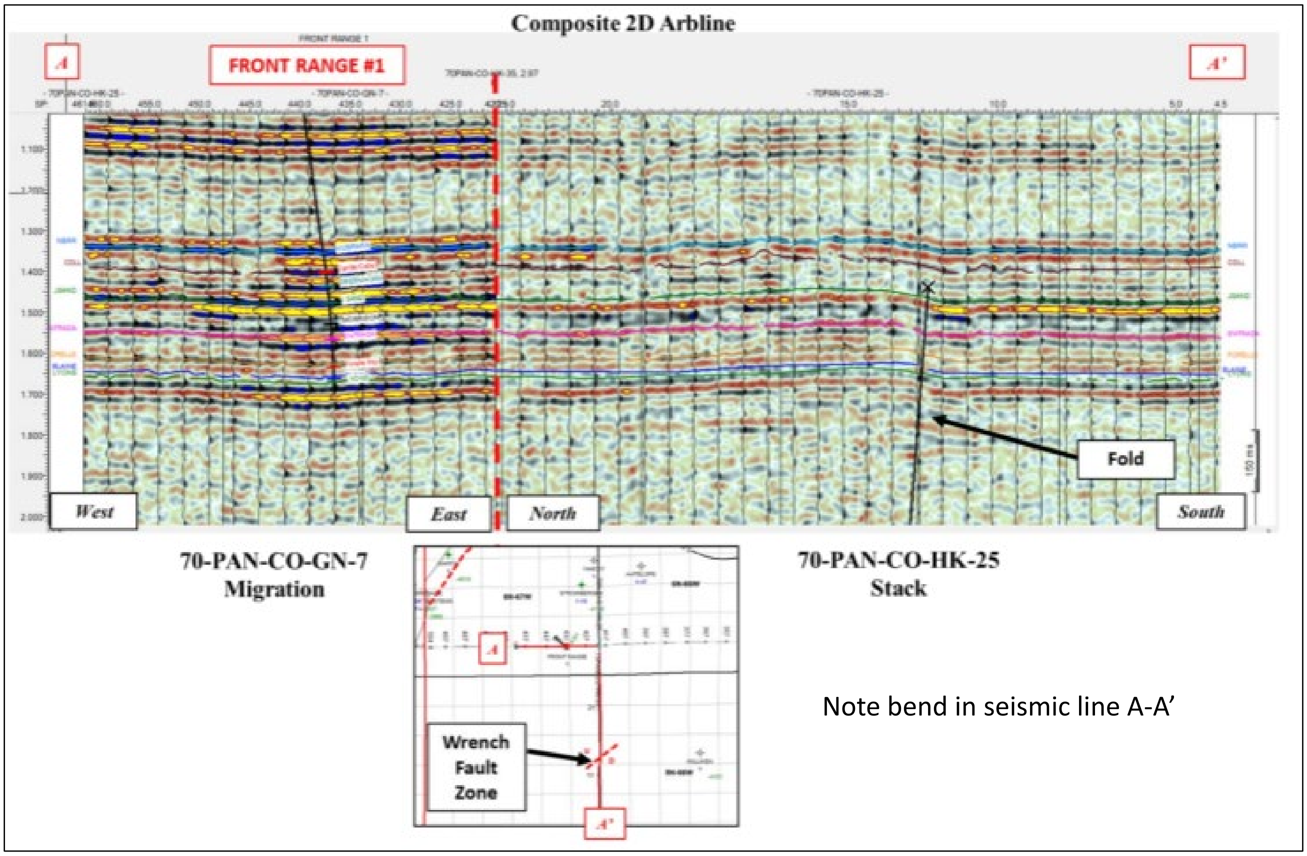


Figure 3. Composite 2D Seismic Line Across the Area of the Front Range 1-1 Well (CSS, 2024).

b. Fracture Analysis Logs:

Schlumberger evaluated fracture transmissivity at the Front Range 1-1 well by analyzing observed fractures in the wellbore's image log. The reconstruction of these fractures (Figure 4) reveals that they are isolated and do not extend into adjacent formations. This isolation suggests a low likelihood of fluid migration through fractures between Underground Sources of Drinking Water (USDWs). Furthermore, variations in total dissolved solids (TDS) concentration and reservoir pressure in adjacent formations indicate that the Lyons formation is isolated from surrounding formations, with no evidence of communicating faults or fractures.

Showing Fracture Clusters Relative To Injection And Confining Formations

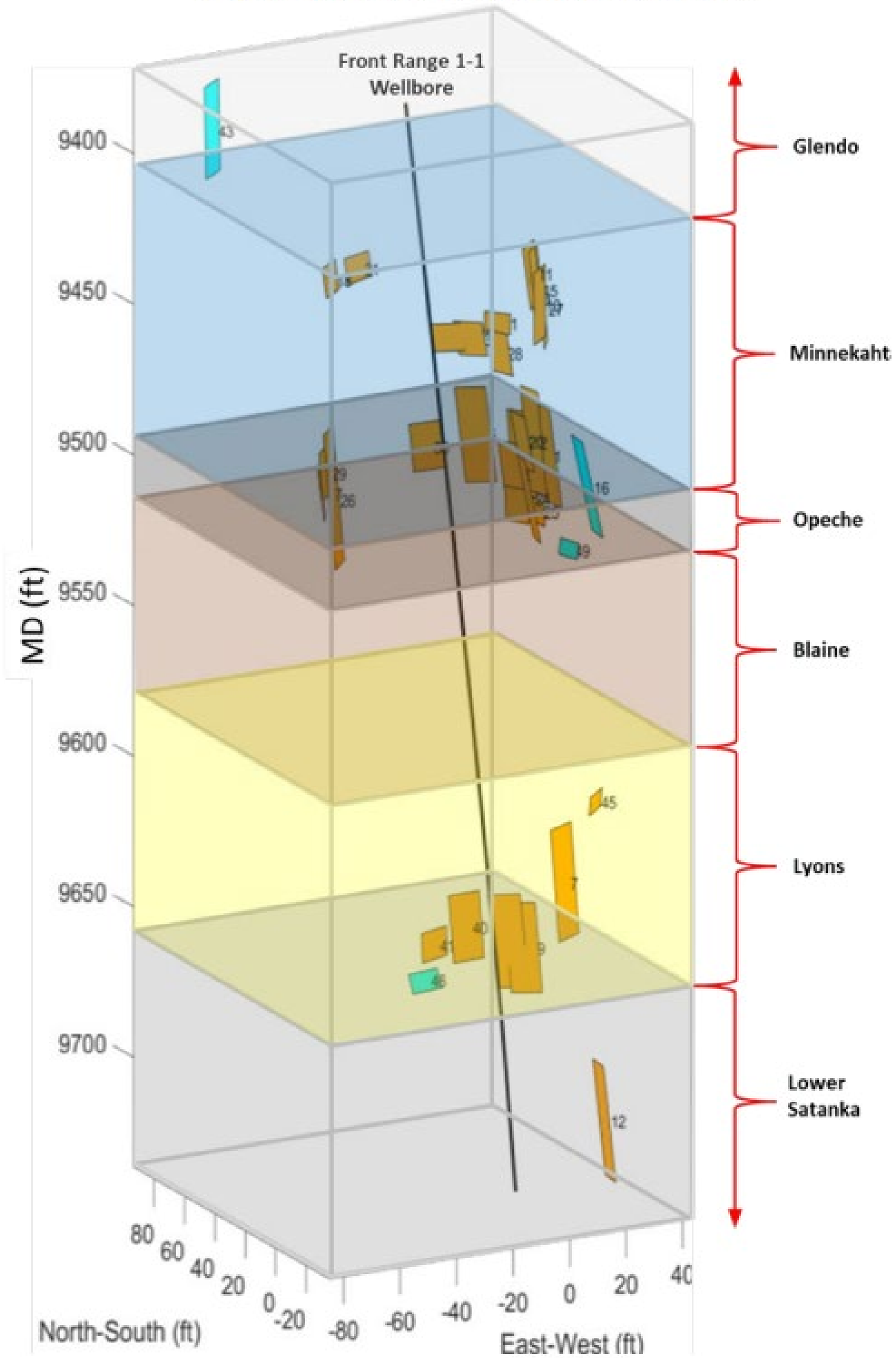


Figure 4. Reconstruction of Fractures Observed in the Image Log of the Front Range 1-1 wellbore (modified from Schlumberger Log Analysis, CSS 2024).

Based on the above information, EPA has concluded that CSS's analyses of structural and geomechanical data indicate that the site meets the requirements at 40 CFR 146.82 and 40 CFR 146.83. See the relevant permit application documents and other supporting materials as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Area of Review Determination

Federal Requirements under the Class VI Rule

Requirements under 40 CFR 146.82 and 40 CFR 146.84(a, b, and c) define the requirements for delineating and reevaluating the project's Area of Review (AoR). The project's AoR is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. For Class VI wells, the AoR is determined by using advanced computational modeling to predict plume development of the injected CO_2 and the underground area of elevated pressure (pressure front) that could result in fluid movement out of the injection zone into USDWs. The injected fluid is referred to as the CO_2 plume once it is underground.

The applicant must conduct computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data. The modeling is used to predict the lateral and vertical migration of the injected CO_2 underground and to predict pressure increase in the injection zone. Determination of the AoR is a key aspect of a Class VI project, and the numerical modeling is expected to be robust and well-documented.

As required at 40 CFR 146.84(e), owners or operators must also periodically re-evaluate the AoR at a minimum fixed frequency of every 5 years over the duration of the project, or when monitoring and operational conditions warrant. The re-evaluation will verify whether the CO_2 plume and pressure front are moving as predicted.

Draft Permit Conditions

Specifics regarding the AoR for the Front Range 1-1 are provided in the AoR and Corrective Action Plan (CAP) found in Attachment B of the Draft Permit. A summary of the application review and decision process is provided below. Reevaluation of, and any needed updates to, the AoR and CAP must be performed every 5 years or when operating conditions or monitoring data indicate the CO_2 plume or pressure front may extend beyond the modeled AoR or that fluids have moved out of the injection zone into USDWs. If the AoR is re-delineated, CSS must revise the project-specific plans described here, and the EPA may need to modify the permit per 40 CFR 144.39.

Application Review and Decision Process

The EPA has reviewed information in the record regarding the AoR. This includes the development of the computational model, the inputs used, how simulations were run, the results, and other information needed to evaluate the modeling approach and interpretation of the results.

Summary:

Carbon Storage Solutions' AoR model utilizes the ECLIPSE 300® numerical simulator, which is designed to simulate multiphase flow and phase transitions of CO_2 and formation fluids under various subsurface conditions. Department of Energy concluded that the model includes essential features necessary for predicting the behavior of injected CO_2.

Key findings indicate that the model's domain is sufficient for delineating the AoR and pressure plume; however, the Department of Energy noted improvements that could be made in the sensitivity analysis (see below).

a. Definition and Delineation of AoR:
The Area of Review (AoR) for a Class VI well is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream, geologic heterogeneities, and is based on available site characterization, monitoring, and operational data [40 CFR 146.84(a)]. These characteristics produce an AoR with an irregular shape around the Front Range 1-1 well with an extent of 6.4 square miles (Figure 5). The AoR is a union of the maximum extent of the pressure front in year 12 (end of injection period) and the maximum extent of the CO_2 plume at year 32 (end of proposed alternate post-injection site care period), (Figure 6), respectively.

b. Methodology for AoR Determination:
The AoR was delineated by using computational modeling to predict the lateral and vertical migration of the CO_2 plume and where the pressure front resulting from injection could push formation fluids (in-situ fluids and injectate) into overlying USDWs if potential conduits, such as abandoned wells, faults, or fractures, are present. Data collected during the stratigraphic test well phase of the project were used to estimate hydrologic characteristics of the Lyons Formation and the overlying and underlying confining zones. Additional data collected during injection testing under the Class V permit corroborated the initial model assumptions for extent and timing.

c. Re-evaluation Frequency and Criteria:
The AoR model will be re-evaluated at least once every 5 years during injection operations. During the post-injection site care period, the model will be reviewed and updated every 5 years. Re-evaluation may also be triggered by significant changes in site operations, monitoring results that differ significantly from model predictions, or new site characterization data that may change model predictions.

DOE Model Review and Summary

Subject matter experts from The Lawrence Livermore National Laboratory of the U.S. Department of Energy (DOE) conducted a review of the computational AoR modeling. This review is an evaluative process designed to ensure the accuracy, reliability, and effectiveness of the computational model used in this project. The DOE's review process encompasses a thorough examination of methodologies, assumptions, data integration, and simulation outcomes.

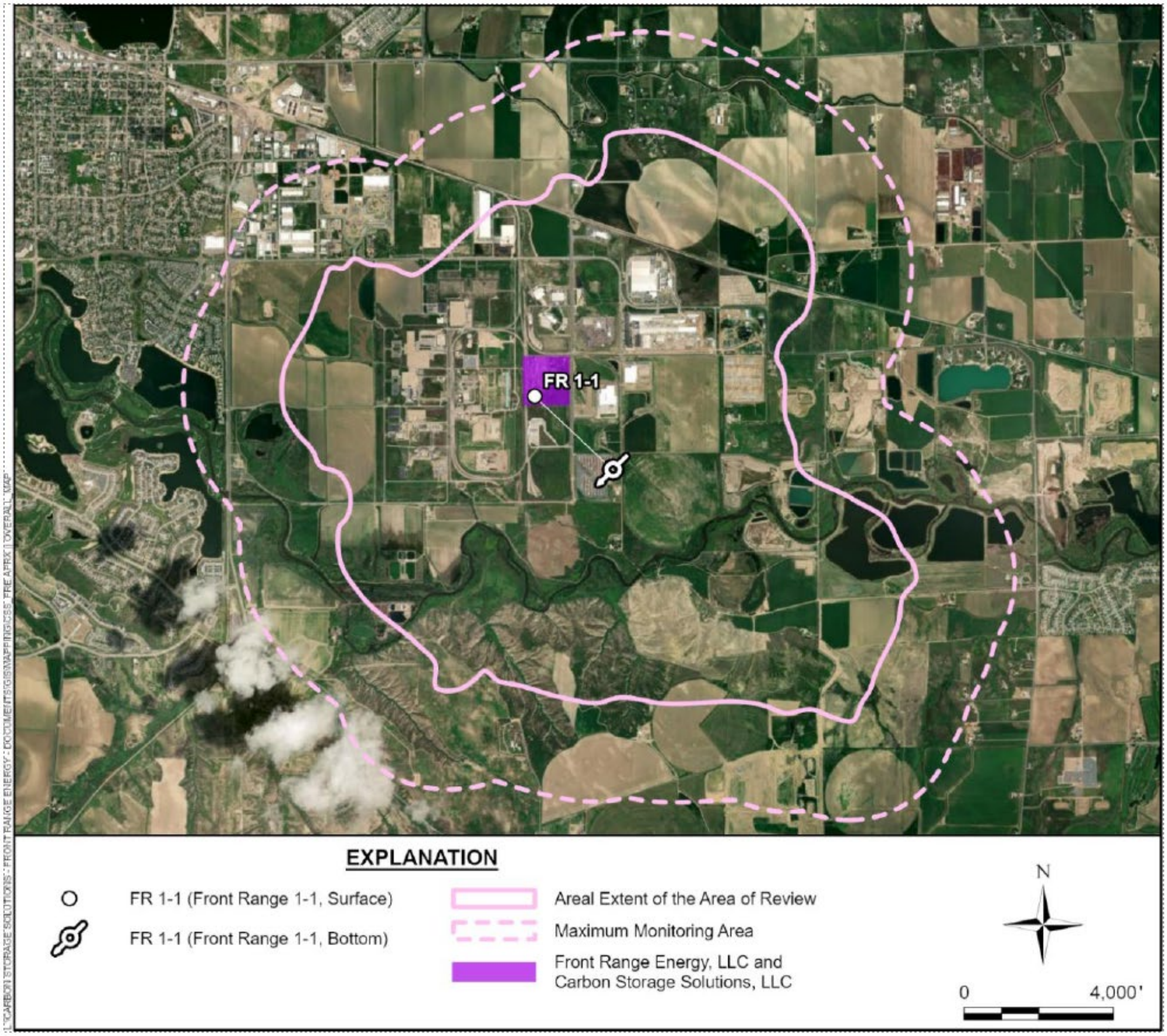


Figure 5. Simulated Extent of the Area of Review for the Front Range 1-1 Injection Well. The solid pink line defines the CO_2 plume at the end of injection. The dashed pink line is ½ mile buffer around the modeled plume extent defined as the maximum monitoring area (MMA) (CSS, 2024).

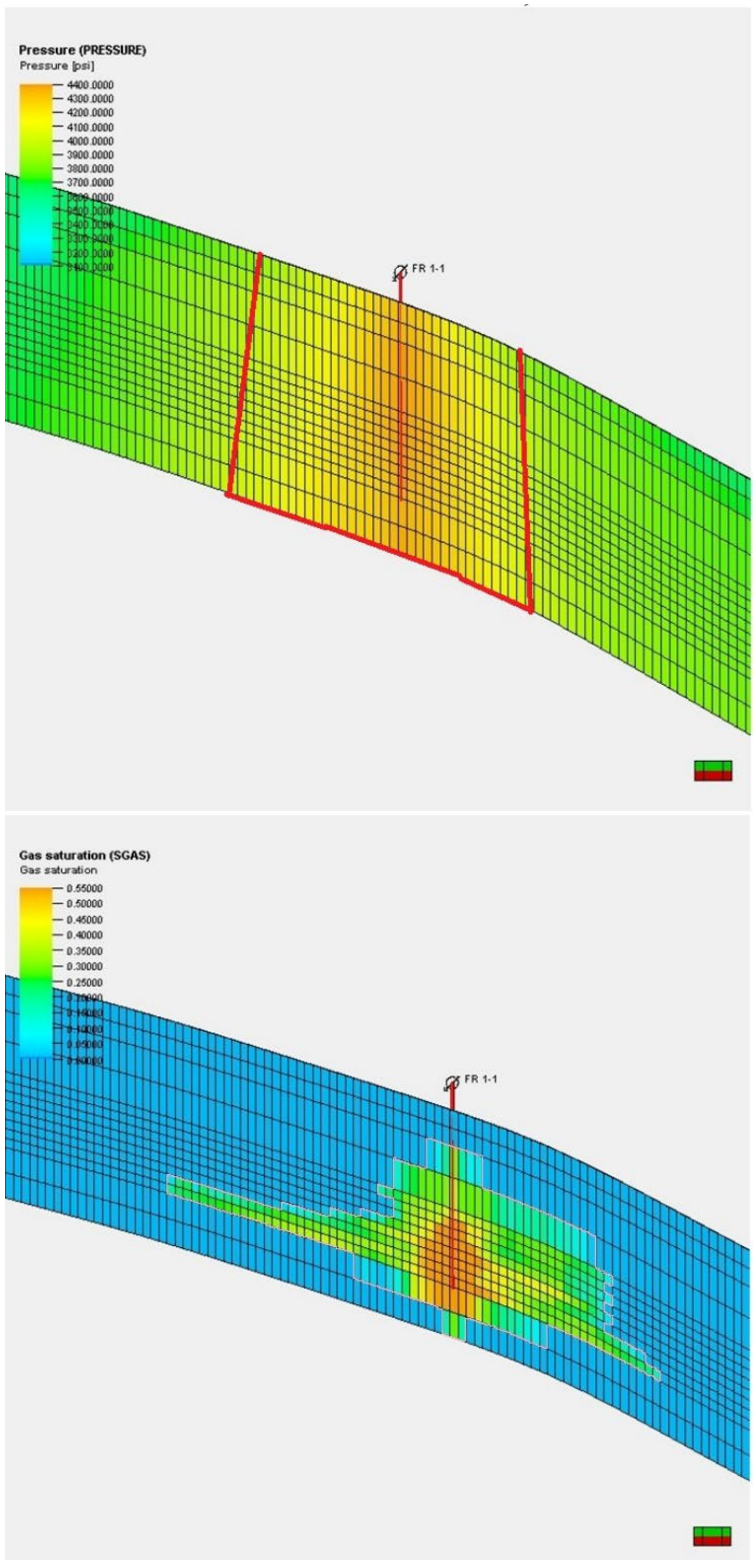


Figure 6. Delineation of Area of Review. Top Panel: Maximum extent of pressure front. Lower Panel: Maximum migration of CO_2 plume through modeled gas saturations. The AoR is a union of these parameters. (CSS, 2024)

Case	Year 32 Plume	
	Areal Extent, mi^2	Change vs. Base Case
Low Permeability (No Credit for Natural Fractures)	4.03	-36.7%
Base Case (30% Credit for Natural Fractures)	6.37	-
High Permeability (100% Credit for Natural Fractures)	6.27	-1.6%

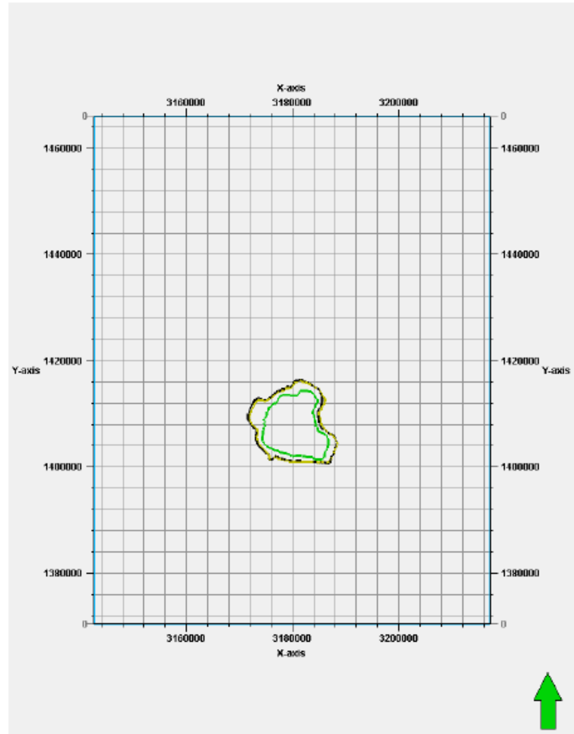


Figure 7. Right: Areal Extent of Year 32 Plumes for Low Permeability Case (Green Line), Base (Black Line), and High Permeability Cases (Yellow-Green Line).

Based on the review of the information provided by the CSS and additional information, the EPA has determined the permit application meets the requirements at 40 CFR 146.84 for AoR determination. See the relevant permit application documents and other supporting materials as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Corrective Action and Wells Within the Area of Review

Federal Requirements under the Class VI Rule

Requirements under 40 CFR 146.182(a)(4) and 40 CFR 146.84(c,d,e), specify that the applicant must identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the injection or confining zones(s). The applicant must determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of CO_2 or other fluids that may endanger USDWs. Owners or operators of Class VI wells must perform corrective action on all wells in the AoR that are determined to need corrective action. Much of this work is presented in the CAP, which identifies existing penetrations of the confining rock layer(s) in the AoR, such as other wells; whether they would pose a risk for CO_2 to migrate out of the injection formation and need remediation (e.g., plugging); and if so, how that corrective action will be performed.

Application Review and Decision Process

The EPA reviewed the CSS CAP and other relevant information to ensure that the plan complies with all requirements.

The only well identified within the AoR that penetrates the confining zones at the Front Range Storage Complex is the Front Range 2-1 deep-zone monitoring well, which is constructed in accordance with Class VI standards to prevent movement of CO_2 or formation fluids out of the injection zone. The only other wells present within the AoR are shallow water production and monitoring wells, with the deepest well reaching a depth of 680 ft below ground surface. There are no oil and gas production or disposal wells located within the AoR. Therefore, no corrective action is necessary to prevent the movement of fluid into or between USDWs.

Underground Sources of Drinking Water (USDWs)

Federal Requirements under the Class VI Rule

Class VI permit applicants are required to submit maps and cross sections showing all USDWs (as well as water wells and springs) within the AoR and where they are situated relative to the injection zone(s) and the direction of water movement, where known (40 CFR 146.82(a)(5)). Applicants must also submit baseline water chemistry data on all subsurface formations, including USDWs, within the AoR (40 CFR 146.82(a)(6)). This information is important to understand where the injection formation is located in relation to USDWs. Injection is not allowed into USDWs.

The UIC program protects current and future sources of drinking water by defining USDW broadly. USDWs, by definition under 40 CFR 144.3 and 146.3, include aquifers currently used by public water supply systems or otherwise used to supply drinking water as well as those aquifers that meet certain criteria indicating they could be used as drinking water, even if they are not currently used. An aquifer or portion of an aquifer that contains fewer than 10,000 milligrams per liter (mg/L) of TDS is considered a potential drinking water source and is therefore protected under the UIC program even if it is not in use.

Application Review and Decision Process

The EPA reviewed the permit application and other relevant information regarding USDWs in the AoR, including formation descriptions, contour maps, cross sections, water quality analyses and determined that they meet the requirements for describing USDWs in the AoR. See the relevant permit application documents and other supporting materials as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

At the Front Range Storage Complex, aquifers identified as USDWs above the injection zone (from shallow to deep) are Quaternary alluvium, Fox Hills Sandstone, Muddy (J) Sandstone, Inyan Kara (Dakota) Formation, and Entrada Sandstone. The lowermost USDW was identified as the Ingleside Formation, which is below the Lyons injection zone. UIC regulations (40 CFR 146.81 et seq; 40 CFR 146.5(f)) generally require that Class VI injection occur below the lowermost USDW. However, the regulations at 40 CFR 146.95 allow for a waiver of this requirement and outline the process for CSS to request an Injection Depth Waiver. Further details are in the section Injection Depth Waiver in this Fact Sheet.

Injection Depth Waiver

Federal Requirements under the Class VI Rule

The EPA is providing notice to the public that CSS has submitted, and EPA is proposing to approve an Injection Depth Waiver application for this project. Class VI permit applicants who intend to sequester CO_2 in reservoirs above the lowermost USDW must submit an injection depth waiver application. This includes a report that provides the following information, in accordance with 40 CFR 146.95(a).

- A demonstration that the injection zone is laterally continuous, is not a USDW or hydraulically connected to USDWs, does not outcrop, and has adequate injectivity, volume, porosity, and appropriate geochemistry.
- A demonstration that the injection zone is bounded by laterally continuous, impermeable confining units, both above and below, to prevent fluid movement and pressure buildup, and that these units are free of transmissive faults and fractures. The report shall further characterize the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs.
- A demonstration, using computational modeling, to show that USDWs above and below the injection zone will not be endangered by fluid movement, with modeling aligned with area of review determinations and subject to periodic re-evaluation.
- A demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of injectate and meet specific construction requirements.
- A description of how monitoring and testing plans will be tailored to the geologic sequestration project to protect USDWs above and below the injection zone.
- Information on the location of all public water supplies affected, likely to be affected, or served by USDWs in the area of review.
- Include any additional information requested by the Director to assist the Regional Administrator's decision on issuing a waiver.

Application Review and Decision Process

The EPA reviewed the injection depth waiver application and other relevant information regarding the Ingleside Formation in the AoR, including formation descriptions, contour maps, cross sections, water quality analyses. The EPA reviewed log data, cross sections and maps, core and geomechanical analyses for the Owl Canyon, the lower confining layer below the Lyons Formation, and found the formation is laterally continuous in the region and is a significantly thick shale, with a porosity of 2.8 % and permeability of 0.0002 mD.

In accordance with 40 CFR 146.95(b)(2), the EPA consulted with the Colorado Department of Public Health and Environment (CDPHE) which has PWSS authority over lands within the area of review. CDPHE coordinates with the Colorado Energy and Carbon Management Commission (ECMC) and Colorado Department of Natural Resources (CDNR). The PWSS Director does not consider the Ingleside Formation to be a viable source of drinking water for the following reasons: a) it is very deep, b) water qualtiy is highly variable, and c) the cost to drill wells to supply quantities of water sufficient for nearby communities would be prohibitive.

Based on the review of the information provided by CSS and additional information, the EPA drafted a report as required by 40 CFR 146.95(b), evaluating the injection depth waiver application from CSS. This report provides a technical evaluation of the elements in 40 CFR 146.95(b)(1). The report concludes that CSS made all the required demonstrations in 40 CFR 146.95 for an injection depth waiver. The EPA evaluation of the depth waiver application found that the confining zones above and below the injection zone provide isolation from adjacent USDWs. For more information, please refer to the injection depth waiver application and the Injection Depth Waiver Evaluation for Geologic Sequestration Permit Number: CO62455-12770 at www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Financial Responsibility

Federal Requirements under the Class VI Rule

Owners and operators are required to demonstrate and maintain financial responsibility for their Class VI projects (40 CFR 146.85). This is to ensure that the private costs of the project are not passed along to the public, including possible costs after injection ends and the well is plugged through site closure. The financial coverage must be sufficient to address endangerment of USDWs. It must cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. The Class VI Rule provides a list of financial instruments to choose from as well as the required conditions of coverage (40 CFR 146.85(a)(1); 40 CFR 146.85((a)(4)(i)).

During the injection period of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation annually and provide this adjustment to the Director. 40 CFR 146.85(c)(2). The owner or operator must also provide to the Director adjustments to the cost estimate after any amendments to the area of review and corrective action plan (40 CFR 146.84), the injection well plugging plan (40 CFR 146.92), the post-injection site care and site closure plan (40 CFR 146.93), and the emergency and remedial response plan (40 CFR 146.94). The Director must approve any decrease or increase to the cost estimate. Whenever the cost estimate increases beyond the face amount of a financial instrument currently in use, the owner or operator must either increase the amount of the financial instrument to equal to the current cost estimate or obtain other financial responsibility instruments to cover the increase. 40 CFR 146.85(c)(4).

Draft Permit Conditions

Per Part G and Attachment H of the draft permit, Carbon Storage Solutions must maintain financial responsibility that meets the requirements of 40 CFR 146.85 for the life of this permit until site closure is approved by the UIC Program Director. CSS must use financial instruments as listed in 40 CFR 146.85(a)(1) to cover all costs associated with the requirements of this permit. Cost estimates must be prepared by a third party that is independent from the corporate structure of the applicant and must be approved by the UIC Program Director, per 40 CFR 146.85(c).

The cost estimates for the covered activities are required to be updated for inflation within 60 days prior to the anniversary date of the establishment of the financial instruments. If there are other updates to the financial responsibility instruments, this information must be submitted on an annual basis. These provisions ensure that resources are available to perform these USDW-protective activities without using public/taxpayer money.

Application Review and Decision Process

The EPA reviewed the financial resources CSS is required to have available to responsibly operate, monitor, and close the project. The EPA reviewed information in the permit application and other relevant information regarding CSS's financial responsibility demonstration to determine if they meet Class VI requirements.

Carbon Storage Solutions has secured financial coverage of $22,097,000 via surety bonds and insurance that will cover injection and monitoring well plugging, post-injection site care, and site closure. Consistent with 40 CFR 146.85(a)(1) and (6), which list insurance and surety bonds as qualifying instruments and provide requirements for using such qualifying financial instruments, CSS procured an insurance policy with Allied World Insurance to cover emergency-and-remedial-response costs and set up a segregated escrow account with US Fire Insurance Company to cover corrective action, injection well plugging, post-injection site care, and site closure costs.

Table 3. Financial Instruments for the Front Range Storage Complex project.

Activity	Estimated Cost to Perform Work, $2024	Financial Instruments	
		Coverage, Current $	Type
Corrective Action	$0	Not Applicable	Not Applicable
Well Plugging and Abandonment	Front Range 1-1: $423K Front Range 2-1: $311K	Front Range 1-1: $465K Front Range 2-1: $342K	Surety
PISC and Site Closure	PISC: $5.4MM Site Closure: $263K	PISC: $6.0MM Site Closure: $290K	Surety
Emergency and Remedial Response	$12.6MM	$15MM	Third Party Insurance
K=thousand			
MM = million			

Based on the information summarized in Table 3, the EPA has concluded that CSS's demonstration of financial responsibility meets the requirements at 40 CFR 146.85. See the relevant permit application documents with information related to financial responsibility as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Well Construction Requirements

Federal Requirements under the Class VI Rule

The regulatory criteria for Class VI well construction are provided at 40 CFR 146.86. All Class VI wells must be constructed with materials (e.g., casings and cement) that are compatible with the fluids with which they may be expected to come into contact. Materials are expected to be exposed to CO_2 and a mixture of CO_2 and water and need to be corrosion resistant.

Class VI wells must be cased and cemented to prevent the movement of fluids into or between USDWs or into unauthorized zones. Requirements include a surface casing (outmost pipe) that extends below the lowermost USDW and at least one long string casing that extends to the injection zone. These casing strings must be cemented to the ground surface. The EPA reviews the proposed construction design and plans for well plugging after injection.

Draft Permit Conditions

The Front Range 1-1 well has already been constructed and permitted as a Class V injection well for testing purposes. Front Range 1-1 is a directionally drilled well. Figures 1 and 2 in Attachment G of the draft permit show the surface and bottom hole locations of the well and the directional wellbore schematic, respectively. The draft Class VI permit requires that the Front Range 1-1 meet the well construction requirements in 40 CFR 146.86. As of January 2026, the injection well meets those requirements.

The draft Class VI permit specifies that the injection well was constructed to inject into the Lyons Formation at a depth of 8,876–8,958 ft below ground surface. The well is deviated and construction includes 3 casing strings. Corrosion-resistant steel was installed for the long string from 0–9,758 ft measured depth and a packer set at 9,500 ft measured depth to isolate the injection formation. The draft permit also requires a deep-zone monitoring well (Front Range 2-1), located about 0.75 miles north of the Front Range 1-1 surface hole location on Front Range Energy property, to monitor the injection zone and the overlying and underlying USDWs. The Front Range 2-1 monitoring well was constructed to similar specifications as the Front Range 1-1 injection well, and it includes sampling ports for the Lyons injection zone and adjacent Entrada and Ingleside USDWs. For specifics on the well construction for the Front Range 1-1 and Front Range 2-1, refer to the review and decision section below.

For details on permit conditions related to injection well construction, see www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Application Review and Decision Process

The EPA reviewed information in the permit application, including well schematics, construction notes, wellbore material, cement quality and corrosion resistance, and other relevant information regarding completed well construction to determine if the proposed Class VI well construction meets requirements.

a. Front Range 1-1 Injection Well

Construction of the Front Range 1-1 well (Table 1; Figure 8a and 8b) complies with Class VI regulations at 40 CFR 146.86, utilizing appropriate casing material and CO_2 resistant cement for a geologic sequestration well. Chromium 13 (13CR) steel was used in the construction of the Front Range 1-1 well, specifically the lower part of the long string casing and injection tubing where they could be in contact with corrosive injection-zone fluids. Geochemical modeling conducted by CSS indicates that the anhydrous CO_2 injectate stream will have minimal corrosion impacts on the tubing material, and the acidity of fluids potentially in contact with the long string casing will be minimal. The Class VI permit for the Front Range 1-1 well includes requirements for corrosion monitoring of well materials by using coupons of the same material placed in the CO_2 flowline and analyzing them on a quarterly basis for signs of corrosion and loss of mass that may be indicative of future potential well integrity issues (40 CFR 146.90(c)). Additional monitoring equipment placed in the tubing-casing annulus above the packer will provide real-time monitoring to help detect failures of the long string casing and/or tubing (40 CFR 146.90(b)). This equipment includes pressure and temperature gauges and fiber optic distributed temperature sensing (DTS) that monitors the wellbore within the tubing casing annulus at a 1-second interval. These data are transmitted to the control center and monitored for changes that may indicate a failure of well integrity, potentially requiring cessation of injection operations and emergency and remedial response.

The cement bond log for the Front Range 1-1 indicates that cement was sufficiently emplaced in the annulus of the long string casing from the injection zone to surface.

Table 1. Construction Parameters for Front Range 1-1, incudes depths, material specs, and cement.

Component	Depth Interval (ft)	Open Hole Diameter	Casing OD	Casing ID	Weight (lb/ft)	Grade
Conductor	0 - 103	36 inches	20 inches	19.5 inches	52.78	A53B
Surface	0 - 2,080	17 1/2 inches	13 3/8 inches	12.615 inches	54.5	J-55
Intermediate	0 - 9,410	12 1/4 inches	9 5/8 inches	8.835 inches	40	HCL-80
Long String	0 - 9,758	8 1/2 inches	7 inches	6.184 inches	29	13CR-80

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	Depth Interval (ft)	Description
CemFIT Heal Slurry	0 to 3,905	Lead cement with a density of 12.0 ppg and a yield of 1.80 ft3/sk

Cement Type	Depth Interval (ft)	Description
MidLead Slurry	3,905 to 8,127	Intermediate cement with a density of 12.0 ppg and a yield of 2.01 ft3/sk
EverCRETE Slurry	8,127 to 9,746	Tail cement with a density of 14.80 ppg and a yield of 2.01 ft3/sk, recommended for CO2 resistance

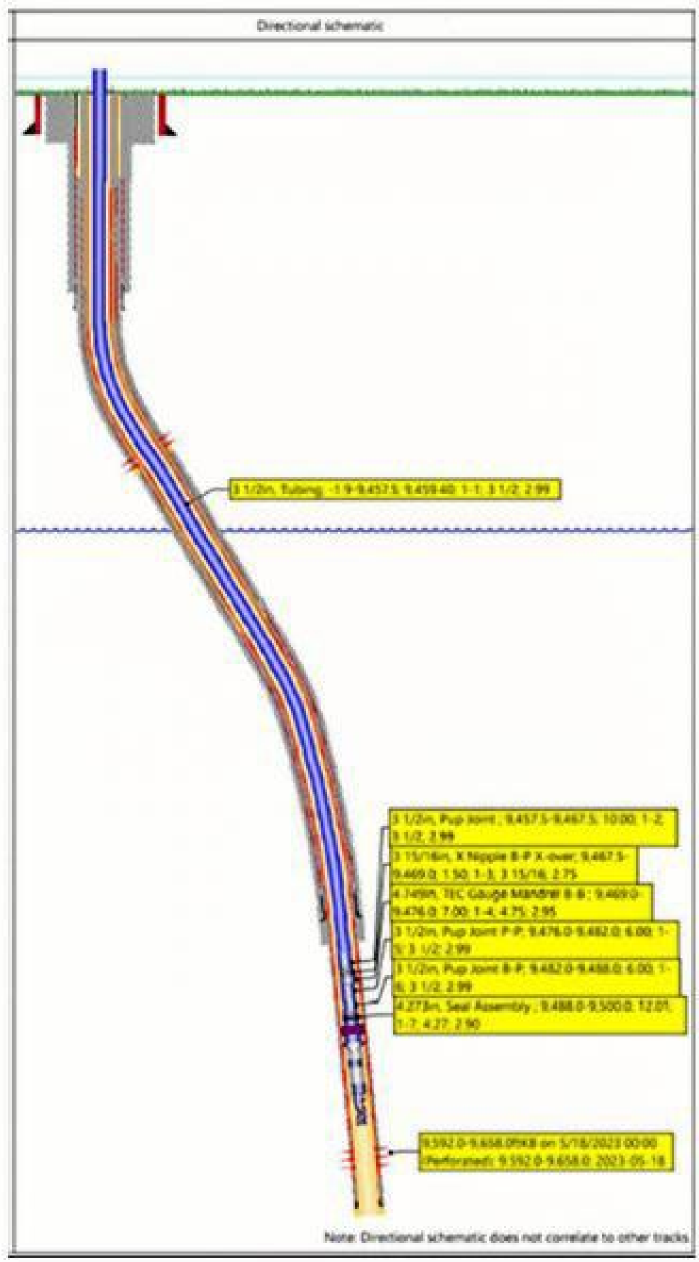


Figure 8a: Directional Wellbore Schematic for Front Range 1-1

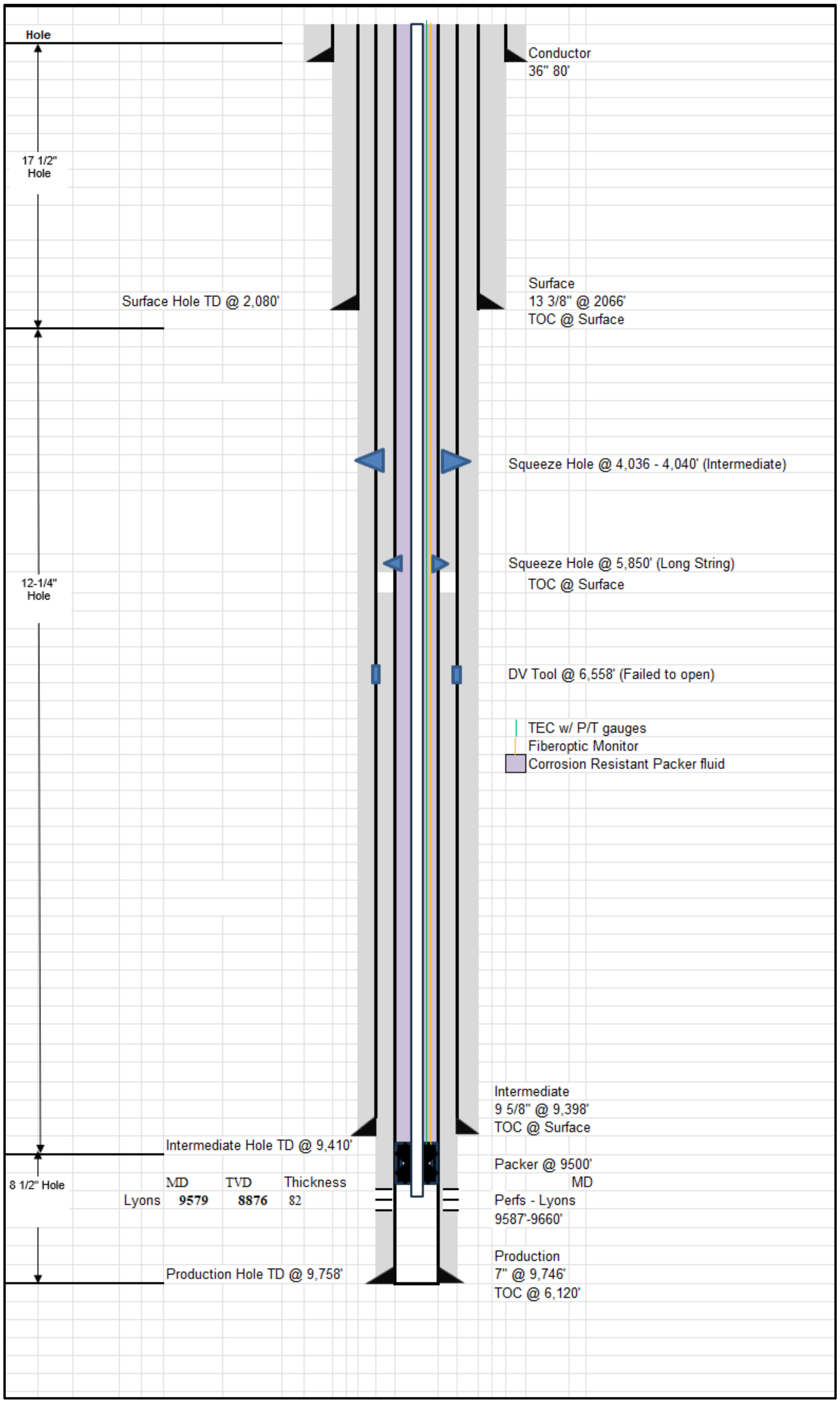


Figure 8b. Schematic of the Front Range 1-1 Injection Well. The diagram shows the current state of construction. Note the injection well is deviated and the measured depth and true vertical depth are different.

b. Front Range 2-1 Monitoring Well

The Front Range 2-1 well was constructed to meet the requirements of 40 CFR 146.86 and was specifically designed as a monitoring well for geologic sequestration. The well penetrates multiple zones, including the upper confining zone, the injection zone, and the lower confining zone, allowing for comprehensive monitoring capabilities. The well is constructed to allow for fluid sampling, direct monitoring of the CO_2 plume and pressure front in the injection zone and for detection of fluid movement out of the injection zone into USDWs directly above and below the injection zone. The well construction (Table 2; Figure 9) utilizes 13CR steel casing materials and CO_2 resistant cement. As discussed above, geochemical modeling conducted by CSS indicates that the anhydrous CO_2 injectate stream will have minimal corrosion impacts on the 13CR material.

The well design incorporates advanced monitoring equipment, including pressure and temperature gauges, as well as fiber optic within the tubing-casing annulus. This design enables real-time monitoring of wellbore conditions at one-second intervals with continuously transmitted data to the command center. This system ensures that any variations in temperature and pressure are promptly detected to characterize plume movement or movement of fluid out of the injection zone.

The cement bond log for the Front Range 2-1 indicates that cement was sufficiently emplaced in the annulus of the long string casing from the Ingleside Formation at 9,804 feet below the surface.

Table 2. Front Range 2-1 internal tubing and water sampling equipment.

Component	Depth Interval (ft)	Open Hole Diameter	Casing OD	Casing ID	Weight (lb/ft)	Grade
Conductor	0 - 80	26 inches	16 inches	15.01 inches	84	J-55
Surface	0 - 2,010	13 1/2 inches	10 3/4 inches	10.05 inches	40.5	J-55
Long String	0 - 6,700	8 1/2 inches	7 inches	6.18 inches	29	HCL-80
Long String	6,700 - 9,390	8 1/2 inches	7 inches	6.18 inches	29	13-CR80

Front Range 2-1 Wellbore Diagram - Vertical Well

API: 05-123-52656

Formation Name	Top (MD)	Bottom (MD)	Hydrogeologic Role
Fox Hills	173'	226'	USDW
Richard	2,393'	2,584'	
Parkman	3,518'	3,827'	
Sussex	4,215'	4,287'	
Shannon	4,599'	4,720'	
Sharon Springs	6,804'	6,842'	
Niobrara	6,842'	7,137'	
Fort Hays	7,137'	7,158'	
Codell	7,158'	7,363'	
Greenhorn	7,363'	7,447'	
Graneros	7,447'	7,589'	
D Sand	7,589'	7,604'	
Huntsman/Mowry	7,604'	7,631'	
Muddy (Dakota J)	7,631'	7,724'	
Skull Creek	7,724'	7,859'	
Inyan Kara (Dakota / Cheyenne	7,859'	7,987'	
Morrison	7,987'	8,197'	
Ralston Creek	8,197'	8,227'	
Entrada	8,227'	8,319'	USDW
Lykins	8,578'	8,578'	Upper Secondary Confining Zone
Freezeout Shale (Member Lyki	8,692'	8,698'	
Forelle (Member Lykins)	8,698'	8,772'	
Glendo (Member Lykins)	8,772'	8,872'	
Opeche Mbr (Up. Satanka)	8,872'	8,902'	Primary Upper Confining Zone
Blaine Evaporite Mbr (Up. Sata	8,902'	8,952'	
Lyons	8,952'	9,027'	Sequestration Zone
Owl Canyon (Lower Satanka)	9,027'	9,256'	Lower Confining Zone
Ingleside	9,256'	9,804'	USDW
Fountain	9,804'	TD	

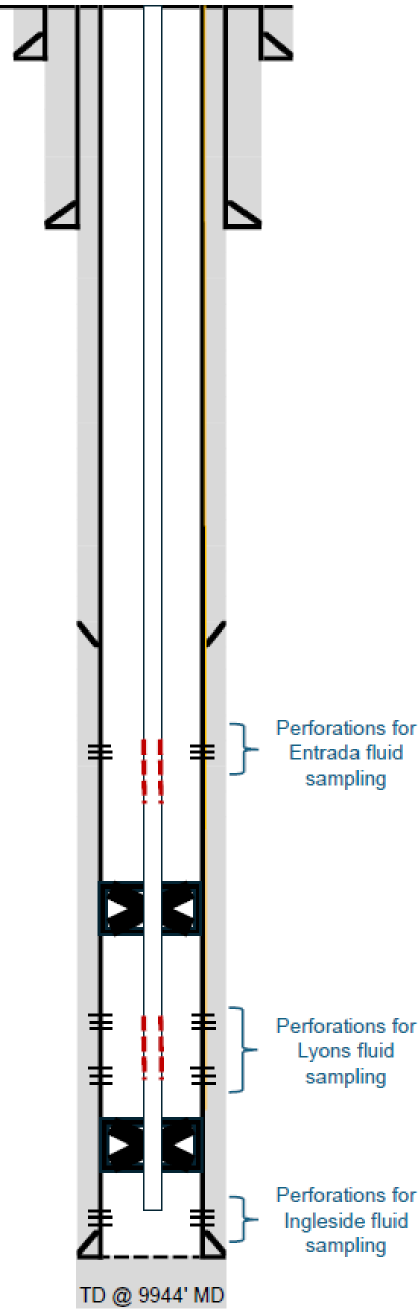


Figure 9. **Wellbore schematic for the Front Range 2-1, including internal mechanisms for fluid sampling of the injection zone and the adjacent USDWs.**

Pre-operational Testing and Authorization to Inject

Federal Requirements under the Class VI Rule

UIC Class VI Regulations at 40 CFR 146.82 require operators to provide specific types of information before the UIC Director can issue a permit. Operators must also meet specific logging, sampling, and testing requirements at 40 CFR 146.87 before operating the injection well. Examples of required logs and tests include resistivity, spontaneous potential, caliper, cement bond, and temperature logs. The operator must also determine or calculate specific information about the injection and confining zones, including the fracture pressure. Operators must also meet mechanical integrity requirements found at 40 CFR 146.89 prior to and during injection well operation.

Draft Permit Conditions

Carbon Storage Solutions is prohibited from commencing injection without authorization. The EPA may grant authorization to inject under the permit following compliance with additional requirements as outlined in the permit and per regulations at 40 CFR 146.82, 146.86, 146.87, and 146.89.

Prior to commencing injection, the permittee shall comply with all requirements in Sections I.10 and J of the permit. The permittee shall perform the testing and logging necessary to demonstrate that the carbon sequestration project will not endanger Underground Sources of Drinking Water (USDWs). The Director must receive verification of compliance, review the submittals, and issue written approval. Injection may not begin until the Director's written approval is obtained.

Application Review and Decision Process

The Front Range 1-1 well has already been constructed and is currently permitted as a UIC Class V well to allow for testing. Thus, CSS has already met several of the pre-operational requirements outlined in regulations and EPA has reviewed the information provided. For example, CSS provided the final well construction procedures. EPA has reviewed this information and determined it meets the requirements of the Class VI regulations. CSS has also already conducted a step rate test, as allowed under their current Class V permit. EPA has reviewed the results of the step rate test and used the resulting injection zone fracture gradient information to determine the maximum allowable injection pressure for the Class VI permit. The requirements outlined in the draft permit reflect what regulatory requirements remain for CSS to complete prior to operations and prior to receiving authorization to inject. The EPA will review any relevant updates based on data obtained during logging and testing of the well and the formation. Using all available data and information, the EPA may grant authorization to inject under the permit following compliance with additional requirements as outlined in the permit and UIC Class VI regulations.

Characteristics of the CO_2 Stream

Federal Requirements under the Class VI Rule

The Class VI Rule at 40 CFR 146.82(a)(7)(iii, iv) requires the applicant to submit information on the source(s) of the CO_2 stream and an analysis of the chemical and physical characteristics of the CO_2 stream. The Class VI Rule defines CO_2 stream as "carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process." 40 CFR 146.81(d). The CO_2 stream, or injection fluid, cannot include anything that meets the RCRA definition of hazardous waste.

At 40 CFR 146.86(c)(3)(ii), the permit applicant must submit information on the characteristics of the CO_2 stream (chemical content, corrosiveness, temperature, and density) so that the Director can determine and specify requirements for the injection tubing and packer.

Draft Permit Conditions

The composition of the CO_2 stream will be greater than or equal to 99% CO_2 with fewer than 10 part per million of hydrogen sulfide (H_2S) based on analyses for the ethanol production process. Prior to issuance of Authorization to Inject, CSS will sample and conduct isotopic analysis on the CO_2 stream for gas saturations. Subsequent injectate stream sampling and analysis must be conducted semi-annually or anytime the source changes. The draft Class VI permit requires that the CO_2 source must be provided by only the Front Range Energy ethanol production facility.

For details on permit conditions related to the sources and physical and chemical characteristics of the CO_2 stream, see Attachment C Testing and Monitoring Plan of the permit.

Application Review and Decision Process

The EPA reviewed the proposed physical (e.g., temperature) and chemical characteristics of the CO_2 to be injected. The EPA reviewed information in the permit application including information on sources, composition, and other characteristics of the CO_2 stream and other relevant information regarding the proposed injection fluid and composition. CSS does not have access to sample the CO_2 currently and sampling will be conducted during startup operations.

Based on the review of the information provided by the CSS and additional information, the EPA determined the permit application meets the requirements for characterization of the injectate as per 40 CFR 146.82(a)(7) and 40 CFR 146.86. See the relevant permit application documents and other supporting materials as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Injection Fluid Volume and Injection Rates

Federal Requirements under the Class VI Rule

The Class VI Rule at 40 CFR 146.83(a)(1) requires an injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream. Thus, the proposed volume of CO_2 to be injected must be consistent with the storage capacity of the injection zone.

The Class VI Rule at 40 CFR 146.82(a)(7)(i) requires the applicant to submit information on the CO_2 injection rate and volume and the total amount of CO_2 that will be injected over the lifetime of the project.

Draft Permit Conditions

The maximum injection rate stipulated by the draft permit is 127,800 metric tons per year with a maximum cumulative injected CO_2 mass of 1.54 million metric tons, which CSS plans to inject over a 12-year period. The Lyons injection zone is capable of receiving this rate and volume of CO_2.

For details on permit conditions related to injection fluid volume and injection rates, see www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Application Review and Decision Process

The EPA reviewed the proposed operating technologies and parameters (injection rate and volume as well as pressure, which is discussed in the next section) and how they would allow for safe operation. The EPA reviewed information in the permit application, including proposed injection volumes and rates, estimates of injection formation storage capacity, and other relevant information regarding the proposed injection fluid and composition.

The Lyons Formation in the project's AoR is a thick (greater than 50 ft), laterally continuous sandstone unit that sits at sufficient depth for CO_2 to be injected and stored. As a well-sorted, quartz-rich sandstone, it has favorable pore space and pathways for fluid movement, which means it can accept CO_2 efficiently and distribute it within the formation without excessive pressure build-up. Across the footprint of the project, the Lyons formation provides a large cumulative pore volume, giving it the capacity to store a substantial amount of CO_2 while maintaining operational control.

Computational modeling conducted for the AoR shows that injection pressures remain below thresholds that could fracture the confining units and that the CO_2 plume remains within the Lyons Formation. These models, calibrated to site data, indicate the formation's injectivity and pore volume are sufficient to accommodate the planned volumes with protective margins. Together, the Lyons Formation's depth, capacity, continuity, and sealing geology make it a suitable reservoir for storing large quantities of carbon dioxide while safeguarding underground sources of drinking water.

Based on the review of the information provided by the CSS and additional information, the EPA determined the injection zone is of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream as per 40 CFR 146.83(a)(1). See the relevant permit application documents with proposed construction information as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Maximum Injection Pressure

Federal Requirements under the Class VI Rule

Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that injection does not initiate fractures in the injection or confining zones, as required under 40 CFR 146.88(a). Such fractures, especially those in the confining zones, could become conduits for the movement of injection or formation fluids into a USDW, which is prohibited. See 40 CFR 146.83(a)(2); 40 CFR 146.88(a); 40 CFR 144.12.

To maintain safe injection, wells must be equipped with continuous recording devices to monitor the injection pressure, rate, volume and/or mass, and temperature of the CO_2 being injected, as well as the pressure on the annulus (space) between the tubing and the long string casing and the volume of fluid in the annulus, as required by 40 CFR 146.88(e)(1).

Injection wells must also be equipped with an automatic surface shut-off system that would shut off the well if any permitted operating parameters—such as injection pressure—diverge from permit limitations, as required by 40 CFR 146.88(e)(2).

Draft Permit Conditions

The downhole maximum allowable injection pressure (MAIP) was set based on 90% of the Lyons Sandstone's fracture pressure to prevent injection pressures from initiating new or propagating existing fractures in the injection and confining zones, which could result in movement of injection or formation fluids into USDWs.

For details on permit conditions related to the downhole maximum allowable injection pressure, see Section K.4; Attachment A, Section 1.0 at www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Application Review and Decision Process

The EPA reviewed information in the permit application and other relevant information regarding the maximum injection pressure and proposed injection well operations to determine if they meet Class VI requirements.

Results of a step rate test performed by CSS at the Front Range 1-1 well indicate the Lyons Sandstone has a fracture gradient of 0.695 pounds per square inch (psi) per foot of depth, which corresponds to a fracture pressure of 6,178 psi at the depth (8,889 ft.) of the top perforation in the Front Range 1-1 well.

The EPA therefore calculated the downhole MAIP as 90% of 6,178, or 5,560 psi. This MAIP must be recalculated if the downhole pressure gauge is not placed at the depth of the top perforation or if testing or monitoring data indicates the formation fracture pressure differs from the current value.

Carbon Storage Solutions does not plan to conduct any formation stimulation for the Front Range 1-1 well. If operational parameters change, such as injection rates decrease or injection pressures increase, CSS must notify the EPA and consult on any changes that may require a permit modification.

Testing and Monitoring Requirements

Federal Requirements under the Class VI Rule

The Class VI Rule at 40 CFR 146.90 requires multiple types of testing and monitoring during CO_2 injection and through site closure. The proposed testing and monitoring procedures are described in a required Testing and Monitoring (T&M) Plan, which is part of the permit application and will be incorporated as an enforceable attachment to the permit, if issued. The draft permit requires that the T&M plan will be periodically updated during the project lifetime (reviewed at least once every five years). The Quality Assurance and Surveillance Plan (QASP) describes the protocol and procedures for conducting the required testing and monitoring.

Specific testing and monitoring requirements in Class VI regulations include:

1. Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics is required at 40 CFR 146.90(a).
2. Continuous monitoring of the injection pressure, rate, volume, pressure on the annulus (space) between the tubing and long string casing, and the volume of annulus fluid added in order to detect the development of any leaks in the casing, tubing, or packer is required at 40 CFR 146.90(b).
3. Requirements for quarterly monitoring of well materials for corrosion are outlined at 40 CFR 146.90(c),

4. Monitoring groundwater quality above and below the confining zones to check for changes that could be due to migration of CO_2. This is done through sampling from deep monitoring wells. This will indicate any changes in water quality, such as changes in pH, major ions, or mobilization of metals or organic compounds that could be caused by injection. This is in accordance with 40 CFR 146.90(d).
5. Testing of the physical condition of the injection well and whether there are leaks in the casing that would allow movement of fluid along the outside of the well ("external mechanical integrity testing"). Testing must be done at least once per year until the well is plugged. The initial baseline test is done prior to injection, as required at 40 CFR 146.90(e). The Class VI Rule specifies the types of tests that are allowed.
6. Testing for changes in the hydrogeologic properties of the injection formation ("pressure fall-off testing") at least once every five years to determine how the formation is responding to injection is required at 40 CFR 146.90(f).
7. Tracking the plume of injected CO_2 and the changes in pressure in the injection formation to verify that the CO_2 plume and pressure are developing as predicted. This is done through a combination of direct measurements (e.g., pressure measurements) and indirect measurements (e.g., using methods such as seismic surveys) to determine the extent of the CO_2 plume as required at 40 CFR 146.90(g)(1,2).
8. The UIC Program Director may require surface air and soil gas monitoring to detect CO_2 movement pursuant to 40 CFR 146.90(h)(2) if such monitoring is based on potential risks to USDWs within the AoR.
9. The UIC program Director may require any additional monitoring necessary to support, upgrade, and improve computational modeling of the area of review evaluation and to determine compliance with the prohibition of movement of fluid into USDWs as described at 40 CFR 146.90(i).

Most testing and monitoring results are required to be submitted in semi-annual reports under 40 CFR 146.91(a). Mechanical integrity test results must be submitted within 30 days as required by 40 CFR 146.91(b). Events where the injected CO_2 or pressure could cause endangerment to a USDW, such as triggering of a shut-off device, a mechanical integrity failure, possible fluid movement into USDWs, or evidence of a surface leak, must be reported within 24 hours as required by 40 CFR 146.91(c).

Draft Permit Conditions

1. CO_2 stream analysis (Part N – Testing and Monitoring Requirements; Attachment C – Carbon Dioxide Stream Analysis)

- The permit requires CSS to analyze the CO_2 stream at least quarterly, collecting a representative sample between the compression system and the Front Range 1-1 and reducing pressure to ~250 psi for gas-phase analysis. Parameters include CO_2 purity, water, total hydrocarbons as methane, total non-methane hydrocarbons, CO, NH_3, and NOx, with chain-of-custody per the QASP, consistent with 40 CFR 146.90(a).

2. Continuous operational monitoring (Part N – Testing and Monitoring Requirements; Attachment C – Continuous Recording of Operational Parameters)

- The permit requires continuous recording of: injection pressure (surface and at the injection interval), injection flow rate and volume, annulus pressure, annulus fluid volume added/produced, and temperature (surface and at the injection interval), consistent with 40 CFR 146.90(b). Attachment C identifies SCADA-based devices and minimum sampling/recording frequencies (e.g., every 10 seconds at the wellhead for pressure and rate).

3. Corrosion monitoring (Part N – Testing and Monitoring Requirements; Attachment C – Corrosion Monitoring)

- The permit requires quarterly corrosion monitoring of injection and monitoring well materials using a corrosion coupon program made from materials matching in-service components (e.g., stainless steel flowline, 13CR alloys for tubing/casing/packer), with assessment of mass/thickness loss, pitting, and cracking using ASTM G1-03 and NACE RP0775, consistent with 40 CFR 146.90(c).

4. Groundwater monitoring above/below the confining zones and in USDWs (Part N – Testing and Monitoring Requirements; Attachment C – Above and Below Confining zones Groundwater Monitoring)

- The permit requires monitoring of groundwater quality and geochemical changes above and below the confining zones(s) and in USDWs per Attachment C, consistent with 40 CFR 146.90(d). The Front Range 2-1 is designated as the deep-zone monitoring well to collect pressure and fluid data in the Lyons injection interval and the adjacent Entrada (above) and Ingleside (below); pressure is recorded continuously at the wellhead. The shallow groundwater monitoring program includes nine wells at six locations and one dedicated lowermost USDW well; shallow wells are sampled quarterly initially, then semi-annually/annually thereafter. Analytical parameters for USDW/shallow wells are listed in Table 8 of Attachment C in the permit. These parameters include select major ions, metals, chemical parameters, dissolved CO_2, and a carbon isotope.

5. Mechanical integrity testing (Part L – Mechanical Integrity; Attachment C – Mechanical Integrity Testing)

- The permit requires annual external MIT by temperature log in accordance with 40 CFR 146.89(c) and 146.90(e) and internal MIT via annual annulus pressure tests plus continuous annulus pressure monitoring in accordance with 40 CFR 146.89(b). Attachment C lists the approved tests, procedures, and frequency.

6. Pressure fall-off testing (Part O– Reporting and Record Keeping; Attachment C – Pressure Fall-Off Testing)

- The permit requires pressure fall-off testing at least once every five years during operations in Front Range 1-1 well to meet 40 CFR 146.90(f); Attachment C includes procedures and data/reporting elements.

7. Carbon Dioxide Plume and Pressure Front Tracking (Attachment C – Carbon Dioxide Plume and Pressure Front Tracking)

- The permit requires 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 CFR 146.90(g)(1) and (2).

- Direct methods: continuous downhole pressure and temperature monitoring in Front Range 1-1 and Front Range 2-1 and baseline/operational fluid sampling in the injection zone to locate the pressure front and plume and calibrate the AoR model (40 CFR 146.90(g)(1)).
- Indirect methods: a baseline vertical seismic profile (VSP) followed by time-lapse VSP surveys every five years; pulsed-neutron logging (PNL) in Front Range 1-1 and Front Range 2-1 on an annual basis per Attachment C and the permit's reporting table (40 CFR 146.90(g)(2)).

8. Surface air and soil-gas monitoring (Part O – 24-Hour Reporting; Attachment C – Near-Surface Soil and Soil Gas Sampling)

- This monitoring requirement was a recommendation from the permittee and is not regulatorily required.
- The permit provides for surface air/soil-gas monitoring under 40 CFR 146.90(h) and requires 24-hour notification to the Director of any release to the atmosphere or biosphere and related surface air/soil-gas monitoring activities under O.3.

9. Seismicity and Fault Monitoring (Attachment C – Seismicity and Fault Monitoring)

- The Project site is located in an area with low rates of natural seismic activity and risk. It is not expected that natural seismicity will affect the Project. CSS will monitor related seismic activity as required in 40 CFR 146.90 to accurately determine the locations and magnitudes of seismic events and identify activity that may indicate failure of the confining zone and possible containment loss.

In accordance with 40 CFR 144.54 and 40 CFR 146.91, and as required by Section O.2 and Attachment A of the draft permit, CSS will submit results of these monitoring requirements to the EPA semiannually, or within 30 days of the completion of a mechanical integrity test or any other testing of the injection well if required by the EPA. Section O.3 of the draft permit requires reporting to the EPA within 24 hours of events where the injected CO_2 or pressure could cause endangerment to a USDW, triggering of a shut-off device, a mechanical integrity failure, possible fluid movement into an unauthorized zone, or evidence of a surface CO_2 leak.

Application Review and Decision Process

The EPA reviewed CSS's proposed T&M Plan and other relevant information to determine whether the T&M Plan meets Class VI requirements. Based on the above information, the EPA has concluded that CSS's T&M Plan as reflected in the draft permit Sections K, M, and N and Attachments A and C meets the requirements at 40 CFR 146.90 and 146.91. See the relevant permit application documents with information related to the T&M Plan as part of the administrative record: Testing and Monitoring Plan (Attachment C of the draft permit) and the Quality Assurance and Surveillance Plan of the permit application. Monitoring after injection has ended, as part of "post injection site care," is discussed in a separate section further below.

Plugging and Abandonment

Federal Requirements under the Class VI Rule

The requirements for an Injection Well Plugging and Abandonment Plan are found at 40 CFR 146.92. The Plugging plan is required by regulation, and once reviewed and approved by the EPA, it is incorporated into the permit and enforceable. The plan must include the measurement of pressure in the injection formation, mechanical integrity testing, and information about the plugs. 40 CFR 146.92(b). The description of the plugging procedures must include the numbers and types of plugs that will be used and where in the well they will be placed, the type of material that will be used, and the method that will be used to place the plugs.

Draft Permit Conditions

The draft permit incorporates the well plugging plan into Attachment D. The plugging plan specifies that the injection well will be plugged using two (2) plugs using various lifts to achieve the plugging plan. Full details for the plugging details are shown in Table 4. Prior to plugging, determination of bottomhole pressure in the injection formation and verification of external mechanical integrity will be done by bottom hole pressure gauge and an approved MIT Part 2 verification tool.

For details on permit conditions related to the Plugging and Abandonment Plan, see www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Table 4. Plug and Abandonment Plan Plugging Details

Plug Information	Squeeze Cement	Plug #1 (Lifts 1-6)	Casing Cement	Plug #2 (Lifts 8 – 19)
Diameter of boring in which plug will be placed, inches	6.184	6.184	8.835	6.184
Depth to bottom of tubing or drill pipe, feet	9,746	9,746	9,398	9,746
Sacks of cement to be used	60	576	831	1,053
Slurry volume to be pumped, cubic feet	75	757	954	1,208
Slurry weight, pounds per gallon	15	15	15.8	15.8
Calculated top of plug, feet	9,370	6,030	0	0
Bottom of plug, feet	9,660	9,370	5,990	5,990
Calculated top of plug, Elevation ft above MSL	-4,618	-1,278	4,752	4,752
Bottom of plug, Elevation ft above MSL	-4,908	-4,618	-1,238	-1,238
Type of cement or other material	CORROSACEM (CO_2 Resistant)	CORROSACEM (CO_2 Resistant)	HALCEM	HALCEM
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Squeeze Cement	Balanced Plug	Retainer	Balanced Plug

ft above MSL = feet above mean sea level elevation referenced to the North American Datum of 1983

Application Review and Decision Process

Carbon Storage Solutions has prepared an Injection Well Plugging Plan for Front Range 1-1 and Front Range 2-1 that meets the requirements of 40 CFR 146.92 and is structured to ensure no movement of fluids into or between USDWs upon well closure. The plan explicitly cites 40 CFR 146.92 and lays out the required elements in Sections P.1–P.5 of the permit, including bottomhole pressure determination, external mechanical integrity testing, plug details and materials, and placement methods, along with notifications and reporting to the UIC Director.

Before plugging, CSS will flush the well with kill-weight brine (without exceeding fracture pressure), determine bottomhole reservoir pressure using the same downhole pressure gauge employed during operations, and verify external mechanical integrity via one of the permitted external MITs (temperature log, noise log, or oxygen activation log). These steps are consistent with requirements at 40 CFR 146.92(a) and 146.92(b)(1) and (2).

The plan describes a plugging program designed to be compatible with the CO_2 stream and to isolate the injection interval and overlying formations. CSS will use CO_2-resistant cement for the injection interval squeeze and the lower plugs, then Class G cement for annular circulation to surface and for the upper plugs. Table 4 specifies plug types, materials, calculated tops and bottoms, slurry weights, and placement methods; CSS will report wet slurry density and retain duplicate cement samples for each plug to support quality verification and regulatory review, consistent with 40 CFR 146.92(b)(3) - (6).

- Squeeze cement into the injection interval perforations, leaving approximately 200 ft of CO_2-resistant cement above the packer.
- Place CO_2-resistant cement in ~500-ft balanced plugs from total depth (bottom around 9,660 ft) up to ~6,030 ft.
- Place twelve additional ~500-ft balanced plugs inside the 7-inch casing to surface.
- Representative slurry weights: ~15.0 ppg for CO_2-resistant cement; ~15.8 ppg for Class G cement; calculated tops and bottoms are provided for each plug stage.
- After all plugs are set, top off the well with cement, cut casings below grade, and install final markers as directed by the agency.

These procedures are designed to ensure long-term isolation and protection of USDWs, consistent with 40 CFR 146.92(b)(3) through (6). The plan also satisfies 40 CFR 146.92(c) by committing to notify the EPA at least 60 days before plugging (or a shorter period as approved), to submit an updated plan with any amendments for EPA approval and permit modification, filing a certified plugging report within 60 days after plugging, and retaining the report for 10 years after site closure. The intent statement emphasizes preventing any fluid or gas migration from the injection zone and protecting USDWs, with allowances to adjust procedures as needed to address field conditions while documenting any significant changes in the plugging report. Based on its review, the EPA has determined that the Plugging and Abandonment Plan meets all applicable Class VI Rule requirements. See the relevant permit application documents with information related to the Plugging and Abandonment Plan as part of the administrative record: www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Post-Injection Site Care (PISC) and Site Closure

Federal Requirements under the Class VI Rule

Following the cessation of injection, CSS must plug the injection well according to their approved Plugging and Abandonment Plan and begin the PISC period. Activities during PISC are done according to the project's PISC and Site Closure Plan, which is approved by the UIC Director. The PISC and Site Closure plan must include certain elements required by regulation, and it is incorporated as an enforceable attachment to the permit, if issued.

The requirements for PISC and Site Closure Plan are found at 40 CFR 146.93. It must include, among other information, predictions about the maximum extent of the increased pressure front in the AoR underground, where the CO_2 plume is expected to be, and how the site will be monitored after injection and for how long. Monitoring during PISC is needed to demonstrate that the migration of the CO_2 plume has plateaued and that pressure is decreasing such that it will return to the native formation pressure prior to site closure. The types of monitoring during PISC will be similar to monitoring during injection under the T&M plan and will involve monitoring groundwater quality and tracking the CO_2 plume and pressure in the injection zone. This will enable confirmation of predictions about plume migration and pressure. At the end of the PISC period, the owner or operator must demonstrate to the UIC Director that the site will not endanger USDWs to receive authorization to close the site. The owner or operator must plug monitoring wells, submit a notice of intent for site closure, and upon closure, restore the site.

UIC Class VI regulations define 50 years as the PISC period, unless the UIC Director approves an alternative timeframe. 40 CFR 146.93(c).

Draft Permit Conditions

For details on draft permit conditions relating to the PISC and Site Closure Plan, see Section O and Attachment E of the draft permit.

The PISC and Site Closure Plan requires monitoring to define the position of the CO_2 plume and pressure front, provide a comparison of data collected to the predictions made by the AoR model and any subsequent updates, and demonstrate that USDWs are not being endangered per 40 CFR 146.90 and 146.93.

During the PISC period, monitoring will continue according to ongoing monitoring plans. These plans include monitoring geochemical changes in shallow groundwater, the Entrada Sandstone, and the Ingleside Formation; conducting pulsed neutron logging and continuous pressure monitoring of the Lyons Sandstone in the Front Range 1-1 and Front Range 2-1; and collecting time-lapse 3D vertical seismic profile data across the site every 5 years.

For this draft permit, the EPA proposes to approve an alternative PISC period of 20 years, instead of the regulatory default of 50 years. The regulations allow such an alternative PISC period if an operator can demonstrate that this is appropriate and ensures non-endangerment of USDWs. 40 CFR 146.93(c). CSS submitted a request for an alternative PISC with its application. The EPA evaluated the submission under the criteria at 40 CFR 146.93(c) and determined that the alternative PISC is protective of USDWs. Furthermore, CSS must provide a non-endangerment report at the end of the PISC phase for Director approval.

At the end of the PISC period, when CSS demonstrates that the site no longer poses a risk of endangerment to USDWs, and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, per 40 CFR 146.93(b)(3), the draft permit requires CSS to plug monitoring wells using multiple plugs of CO_2-resistant cement and the retainer and balance methods. To complete the site closure, CSS will remove all drilling and production equipment, machinery, and debris from the site, will weld steel plates over the plugged and abandoned wells, and will fill all excavations, holes, and pits. The draft permit requires CSS to obtain EPA approval for site closure. Table 5 below summarizes the PISC monitoring plans to begin following the cessation of injection.

For details on permit conditions related to the PISC and Site Closure Plan, see www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Table 5. Post Injection Site Care Monitoring Requirements

Monitoring Activity	PISC Frequency	Wells	Location
Groundwater Monitoring			
Shallow Groundwater Sampling	Biannual: Years 1-5 Annual thereafter (Q2 of each year)	CSS-owned groundwater wells	Varying (Shallow and Deep Pierre)
Deep groundwater sampling	Annual: Years 1 – 5, Every 5 years (Q2 of each year)	Front Range 1-1 Front Range 2-1	Entrada Ingleside
Pressure Monitoring			
Downhole Pressure: Years 1-5 Years 6 – 20	Continuous Annual static survey	Front Range 1-1 Front Range 2-1	Above Packer Above Packer
Wellhead Pressure: Years 1-5 Years 6 – 20	Continuous (10 sec to 60 min) Every 24 hours	Front Range 1-1 Front Range 2-1	Surface Surface
Annulus Pressure: Years 1-5 Years 6 – 20	Continuous (10 s) Every 24 hours	Front Range 1-1 Front Range 2-1	Surface Surface
Mechanical Integrity Tests [4]			
External MIT: Temperature Logging	Annual Annual for first five years	Front Range 1-1 Front Range 2-1	Surface to well bottom Surface to well bottom
CO_2 Plume Verification Monitoring			
Pulsed Neutron Logging (PNL)	Year 1, Year 3, Year 6, then five-year intervals to Year 20	Front Range 1-1 Front Range 2-1	ACZ Interval Confining Zone Injection Zone
Time-lapse VSP Seismic Data	Every 5 years, plus one survey at the end of PISC	Area sufficient to image an CO_2 plume	Imaging CO_2 plume and overburden

Application Review and Decision Process

EPA reviewed CSS's alternative PISC demonstration, which was based on significant site-specific data and information provided via the application documents, submissions in response to EPA's Requests for Additional Information, technical discussions with the applicant, and siting criteria, as required by 40 CFR 146.93(c). CSS's alternative PISC timeframe demonstration includes substantial evidence to support the conclusion that the project will not pose a risk of endangerment to USDWs at the end of the 20-year timeframe.

The key ways in which the site-specific data and information in the demonstration supports a 20-year alternative PISC timeframe and addresses risk to USDWs are as follows: the computational modeling demonstrated that the CO_2 plume will stabilize by year 13 of the PISC timeframe and that the pressure front will dissipate to native levels by year 20 of the PISC timeframe. The modeling shows that the site-specific processes that will occur in the Lyons Formation injection zone will result in appropriate trapping of the injected CO_2 to ensure uniform capture, storage, and movement of the CO_2. The predicted rates of the various trapping phases demonstrate that 99% trapping will be complete by year 20 of the PISC timeframe. There is significant separation (approximately 600 feet) between the top of the injection zone (Lyons) and the bottom of the lowest/nearest USDW (Entrada), including the Lykins confining layer located in between, which is of appropriate thickness, permeability, and integrity to prevent vertical migration of the CO_2 plume at year 20 post-injection and beyond and is free of fractures and faults that could provide a pathway for fluid movement into a USDW. There are no wells in the AoR except wells associated with this project. The construction of the injection well (Front Range 1-1) will ensure CO_2 injection occurs only at depth within the Lyons Formation injection zone. Together, all these elements demonstrate that the CSS project will not pose a risk of endangerment to USDWs after the 20-year PISC timeframe.

Based on the substantial evidence contained in the draft permit administrative record, including the alternative PISC demonstration, EPA concludes that CSS has demonstrated that the well will no longer pose a risk of endangerment to USDWs at the end of the 20-year alternative PISC timeframe.

Emergency and Remedial Response

Federal Requirements under the Class VI Rule

The Emergency and Remedial Response Plan (ERRP) establishes requirements for the operator to respond to potential injection-related compliance issues that could endanger USDWs should they arise. Requirements for the Emergency and Remedial Response plan (40 CFR 146.94) specify that the plan must describe what the owner or operator will do in the unanticipated circumstance where unintended movement of the injected fluids occurs during the construction, operation, or PISC periods. The Emergency and Remedial Response plan (40 CFR 146.94(b)(1-4)) is an enforceable part of the permit that describes the response actions that the permit applicant must take to address adverse events related to the unintended fluid movement. If there is an indication that the injected CO_2 and associated pressure may endanger a USDW, the owner or operator must stop injection, identify and characterize any release, notify the UIC Director within 24 hours, and implement the approved emergency and remedial response plan. The plan identifies the staff and equipment available to support emergency and remedial response events. The emergency and remedial response provisions of the permit will facilitate expedient responses and prevent or mitigate harm to USDWs.

Draft Permit Conditions

Section O.3 of the draft permit requires reporting to the EPA within 24 hours of events where the injected CO_2 stream or associated pressure front could cause endangerment to a USDW, such as triggering of a shut-off device, a mechanical integrity failure, possible fluid movement into an unauthorized zone, or evidence of a surface leak. Section Q of the draft permit contains the requirement that the applicant must take actions to address movement of the injection or formation fluids that may cause an endangerment to a USDW and must maintain and comply with an approved ERRP and 40 CFR 146.94.

Attachment F of the draft permit incorporates the ERRP and contains required actions that the permittee must implement in the event of various emergency scenarios.

For details on the permit conditions related to the Emergency and Remedial Response Plan, see Section Q and Attachment F of the draft permit.

Application Review and Decision Process

The EPA reviewed CSS's ERRP and concluded that it identifies key resources and infrastructure in and around the project area, including USDWs, surface bodies of water, population centers, sensitive receptors, infrastructure related to oil and gas production, and public infrastructure including a park, pool, church, and the Front Range Energy Ethanol plant within the AoR. The plan identifies procedures for potential risk scenarios that may occur during construction, operation, and post-injection site care periods, including a well construction event, well integrity failure, monitoring equipment failure, severe weather disaster, evidence suggesting potential leakage to a USDW or other unauthorized zone (including the surface), and seismic events. The ERRP also identifies the staff and equipment available to support emergency and remedial response events, includes contact information for local/state authorities, discusses the emergency communications plans, and includes procedures for periodic review of the ERRP. The plan requires CSS to initiate a shutdown plan for the affected well if CSS obtains any evidence that the injected carbon dioxide stream and/or associated pressure front may cause an endangerment to a USDW. The plan also identifies circumstances when CSS must provide 24-hour notification to the EPA.

Finally, consistent with 40 CFR 146.94(d), CSS will be required to review the ERRP periodically, no less than every five years, but also following any reevaluation of the AoR or significant facility changes or as otherwise required by the UIC Program Director.

The EPA has determined that the ERRP meets all applicable Class VI Rule requirements. See Attachment F of the draft permit at www.regulations.gov Docket # EPA-R8-OW-2026-1915.

Other Permit Information

Variances or alternatives to required standards under 40 CFR 124.8(b)(5)

Justification for the requested injection depth waiver and alternative PISC timeframe have been described above. The draft permit has no other proposed alternatives to required standards.

Endangered Species Act (ESA)

The UIC regulations at 40 CFR 144.4. provides a list of Federal laws that may apply to the issuance of Class VI permits, including that "[t]he Endangered Species Act, 16 U.S.C. 1531 et seq. Section 7 of the Act and implementing regulations (50 CFR part 402) require the Regional Administrator to ensure, in consultation with the Secretary of the Interior or Commerce, that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat."

<u>Application Review and Decision Process</u>

In accordance with 40 CFR 144.4, EPA evaluated ESA obligations for the proposed Class VI action using the U.S. Fish & Wildlife Service Information for Planning and Consultation (IPaC) system to identify federally listed or proposed species and designated or proposed critical habitat potentially present in the action area and to inform its assessment of potential effects to such species or critical habitat. EPA reviewed the wells, well pad, and a 0.5-mile area surrounding the well locations and considered connected actions that could affect listed species. The project will use existing roads and project-related activities will occur within the 0.5-mile action area surrounding the well on land with historical and existing disturbance. To assess potential effects, EPA supplemented the IPaC information with:

- Colorado Conservation Data Explorer (CODEX) and Colorado Parks & Wildlife species-range information (e.g., for Preble's meadow jumping mouse and piping plover).
- Colorado DWR stream data to evaluate habitat suitability for aquatic species (pallid sturgeon).
- USFWS Monarch migration information and ArcGIS aerial imagery to evaluate land cover and host-plant availability for monarch butterflies near the well locations.

Species identified by IPaC for the facility area and effects determinations:

- Mammal: Preble's meadow jumping mouse (Threatened);
- Birds: Piping plover (Threatened); Whooping crane (Endangered); Eastern black rail (Threatened);
- Fish: Pallid sturgeon (Endangered);
- Insect: Monarch butterfly (Proposed Threatened);
- Flowering plants: Western prairie fringed orchid (Threatened); Ute ladies'-tresses (Threatened; proposed for delisting by USFWS).

There is no designated or proposed critical habitat within the action area. The EPA will proceed in a manner consistent with ESA requirements.

National Historic Preservation Act (NHPA)

40 CFR 144.4. provides a list of Federal laws that may apply to the issuance of Class VI permits, including that "The National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq. Section 106 of the Act and implementing regulations (36 CFR part 800) require the Regional Administrator, before issuing a license, to adopt measures when feasible to mitigate potential adverse effects of the licensed activity and properties listed or eligible for listing in the National Register of Historic Places. The Act's requirements are to be implemented in cooperation with State Historic Preservation Officers and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation."

Application Review and Decision Process

Pursuant to Section 106 of the National Historic Preservation Act and its implementing regulations at 36 CFR Part 800, the U.S. Environmental Protection Agency will evaluate the potential effects of the proposed permitting action on historic properties. Section 106 requires federal agencies to consider the effects of their undertakings on properties listed on or eligible for listing in the National Register of Historic Places and to provide the Advisory Council on Historic Preservation with a reasonable opportunity to comment. As part of this process, EPA will identify the Area of Potential Effects associated with the proposed project, consult with the appropriate State Historic Preservation Office, any applicable Tribal Historic Preservation Office, and other consulting parties, and evaluate whether historic properties may be present and whether the undertaking may result in effects to such properties. If historic properties are identified within the Area of Potential Effects, EPA will assess the nature of any potential effects and, if necessary, consult with appropriate parties to avoid, minimize, or mitigate adverse effects in accordance with 36 CFR Part 800. EPA will complete its Section 106 review prior to making a final permitting decision.

Issuance and Effective Date of Permits

In accordance with 40 CFR 124.15, the permits would become effective immediately upon issuance if no public comments were received that requested a change in the draft permit. However, in the event that public comments are received requesting changes, and the EPA decides to issue final permits, then the permits would become effective 30 days after the date of issuance unless a different effective date is specified in the decision or the permits are appealed.

Duration of Permit

In accordance with 40 CFR 144.36(a), the permit would be in effect for the duration of the project unless it is otherwise modified, revoked and reissued, or terminated as provided at 40 CFR 144.39, 144.40, and 144.41.

Modification, Revocation and Reissuance, and Termination

Section B.1 of the permit states some conditions that may warrant modification, revocation and reissuance, or termination of the permit. The EPA may modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40 and any other applicable law. The permit is also subject to modifications as specified in 40 CFR 144.41.

Acronyms

AoR	Area of Review

CO_2	Carbon dioxide
EAB	Environmental Appeals Board
EPA	Environmental Protection Agency
ERRP	Emergency Remedial Response Plan
ORC	Office of Regional Counsel
PISC	Post-injection site care
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water