REGION 6 UNDERGROUND INJECTION CONTROL
CLASS VI PERMIT

PERMIT ID: R6-TX-245-C6-0001

WELL NAME: Rose CCS No. 01

ISSUED TO:
ExxonMobil Low Carbon Solutions Onshore Storage LLC
22777 Springwoods Village Parkway
Spring, TX 77389

REGION 6

DALLAS, TX 75270

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

PERMIT NUMBER: R6-TX-245-C6-0001

FACILITY NAME: Rose Carbon Capture and Storage

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, and 146 and according to the terms of this Permit,

ExxonMobil Low Carbon Solutions Onshore Storage LLC

hereinafter referred to as the "Permittee," is authorized, upon issuance of authorization to commence injection, to operate the following Class VI well:

LaBelle Properties Ltd #1
(Rose CCS Project Injection Well No. 01)
Fannett, TX
Latitude: 29.999678
Longitude: -94.285108

This well will inject one carbon dioxide stream (also referred to as CO2 in this Permit and following attachments) sourced from high-concentration industrial sources, including clean hydrogen, ammonia, direct-reduced iron plants, and natural gas treatment facilities that feed into ExxonMobil's Gulf Coast CO2 pipeline network. The Permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N - REPORTING AND RECORDKEEPING of this Permit.

The carbon dioxide stream, as characterized in the Permit application and the administrative record, shall be a supercritical fluid. Injection for this well is authorized into the Fleming Formation at a depth of approximately 3,486 feet to 6,077 feet below mean sea level (BMSL) and into the Frio Formation at a depth of approximately 6,483 feet to

8,463 feet (BMSL) upon the express condition that the Permittee meets the restrictions set forth herein. The designated upper confining zones for this injection are the Amphistegina 'B' shale, in addition to the Anahuac Shale.

This Permit is for the conversion and operation of one Class VI injection well. Injection shall not commence until the Permittee has received written authorization to inject from the Director of the Water Division of EPA Region 6 (Director), in accordance with Section R - COMMENCING INJECTION of this Permit.

Any underground injection activity not authorized by this Permit is prohibited. All references to 40 CFR are to the regulations in effect on the date that this Permit is effective and, should renumbering occur, their subsequent equivalent. The following attachments are excerpts of specific elements from the Permittee's application that are incorporated into this Permit by reference and as enforceable conditions:

1. Summary of Operating Requirements
2. Area of Review (AoR) and Corrective Action Plan
3. Financial Responsibility Demonstration
4. Construction Details
5. Stimulation Plan
6. Testing and Monitoring Plan
7. Well Plugging Plan
8. Post-Injection Site Care and Site Closure Plan
9. Emergency and Remedial Response Plan

Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the SDWA or any other law governing the protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with applicable UIC regulations (i.e., those requirements of the UIC regulations that are directly enforceable regardless of their inclusion as a condition of the permit).

This Permit shall become effective thirty days after notice of issuance, subject to the conditions in Section A - EFFECT OF PERMIT, and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed unless this Permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 124.5, 144.12, 144.39, 144.40 or 144.41. This Permit shall also remain in effect upon delegation of primary enforcement responsibility to a new entity until such time as the new entity issues its own Permit to the Permittee or chooses to adopt this Permit as its own Permit.

The Permit will expire in two years if the Permittee fails to receive, written authorization to inject from the Director of the Water Division of EPA Region 6 (Director), in accordance with Section R - COMMENCING INJECTION of this Permit or the Director's approval of a written request in electronic format for an extension of this two-year period. Requests for extension must state reason(s) for delay, an estimated completion date, and if applicable list additional wells that penetrate the designated confining zone within the Area of Review

(AoR) which were not included in the initial Permit application, including well construction diagrams, cement records, and cement bond logs for any new AoR wells.

The Permittee must reevaluate the AoR and comply with 40 CFR 146.84(e) at least every five years from the effective date specified above. If the results from the reevaluated AoR are different from what is predicted in the Permittee's application, the EPA may require the Permittee to update its Permit application within the Geologic Sequestration Data Tool (GSDT).

Authorization Signed By:

____

Regional Administrator
U.S. Environmental Protection Agency, Region 6
Date Signed:

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit and with an authorization to inject. Notwithstanding any other provisions of this Permit, the Permittee authorized by this Permit must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus, or formation fluids into underground sources of drinking water (USDWs) or any unauthorized geologic zones. The objective of this Permit is to prevent the movement of fluids into or between USDWs or into any unauthorized geologic zones consistent with the requirements at 40 CFR 146.86(a) and 144.12(a) and (b). Any underground injection activity not explicitly authorized in this Permit is prohibited. For purposes of enforcement, compliance with this Permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA; nor does compliance with the Permit shield the Permittee from its independent obligation to comply with those requirements of the UIC regulations that are directly enforceable regardless of their inclusion as a condition of the Permit.

Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this Permit, nor compliance with its terms, shall be construed to relieve the Permittee of any duties under applicable federal, state, or local laws or regulations that are not preempted or superseded by the federal SDWA Underground Injection Control (UIC) program.

In accordance with 40 CFR 124.15(b), the effective date of the Permit is thirty days after notice of issuance, except that the Permit shall not become effective (1) until the financial responsibility demonstration in ATTACHMENT 3: FINANCIAL RESPONSIBILITY DEMONSTRATION is fully effective or (2) if the Permit is appealed pursuant to 40 CFR 124.19. If the Permit is appealed, the effectiveness of uncontested conditions is governed by the procedures at 40 CFR 124.16.

B. PERMIT ACTIONS

1. **Modification, Revocation, and Reissuance, or Termination:** The Director may, for cause or upon request from any interested person, including the Permittee, 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.

2. **Minor Modifications:** Upon the consent of the Permittee, the Director may modify this Permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not

processed as a minor modification under 40 CFR 144.41 must be made for cause and follow the procedures in 40 CFR 124 for preparing a draft permit and issuing public notice, as required in 40 CFR 144.39.

3. **Transfer of Permit**: This Permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section N(6)(b) - REPORTING AND RECORDKEEPING of this Permit.

4. **Permittee Change of Name or Address**: The Permittee shall notify the Director at least 30 days in advance of any changes to the Permittee's legal name, address, or the address where records are kept. The Permit may be subject to a modification in accordance with item (1) of this section.

C. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this Permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA under this Permit may be claimed as containing trade secret, proprietary, or confidential business information which is protected under Exemption 4 of the Freedom of Information Act at 5 U.S.C. 552(b)(4) by the submitter. Any such claim must be asserted at the time of submission by clearly marking the words "confidential business information" or “proprietary business information” on every page containing such information. Also, the Permittee shall provide, if requested, a detailed report substantiating all such claims. The report should include, but not be limited to, information on why disclosure would cause harm, the portions of information entitled to confidential treatment, etc. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be treated in accordance with the procedures in 40 CFR Part 2. Claims of confidentiality for the following information will be denied:

1. The name and address of the Permittee; and

2. Information that deals with the existence, absence, or level of contaminants in drinking water.

E. DEFINITIONS

All terms used in this Permit shall have the meaning set forth in the SDWA and UIC regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless expressly stated otherwise, all references to “days” in this Permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Prohibition of Movement of Fluid into a USDW:** The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates that a well covered by this Permit may have caused the movement of any contaminant into the USDW, the Director may take enforcement action or prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to remediate and prevent such movement. The Director may also take enforcement action per 40 CFR 144.12(a), (b), and (e).

2. **Duty to Comply**: The Permittee must comply with all conditions of this Permit. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, Permit termination, revocation, reissuance, modification, or denial of a Permit renewal application, except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency Permit under 40 CFR 144.34 and 144.51(a).

3. **Duty to Reapply:** If the Permittee wishes to continue an activity regulated by this Permit after its expiration, the Permittee must apply for and obtain a new Permit, per 40 CFR 144.51(b).

4. **Penalties for Violations of Permit Conditions:** Any person who violates a Permit requirement is subject to civil penalties and other enforcement action under the SDWA, 42 USC 300h-2. Any person who willfully violates Permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

5. **Need to Halt or Reduce Activity Not a Defense:** It shall not be a defense for the Permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this Permit per 40 CFR 144.51(c). Enforcement actions may require the Permittee to halt or reduce injection activities.

6. **Duty to Mitigate:** The Permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse environmental impact resulting from noncompliance with this Permit under 40 CFR 144.51(d).

7. **Actions not Authorized:** Issuance of this Permit does not convey property rights of any sort or any exclusive privilege per 40 CFR 144.51(g); nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of state or local laws or regulations. Nothing in this Permit, nor compliance with its terms, shall be construed to relieve the Permittee of any duties under State or local laws or regulations that are not preempted or superseded by the federal SDWA UIC program.

8. **Enforceability during Modification:** The filing of a request for a Permit modification, revocation, reissuance, termination, notification of planned changes, or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit, per 40 CFR 144.51(f). The Permittee shall notify the Director at least 30 days in advance of any modification for review and approval prior to the modification activity.

9. **Proper Operation and Maintenance:** The Permittee shall always properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) that are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance include effective performance, adequate funding, adequate Permittee staffing and training, accurate laboratory and process controls, and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to comply with this Permit's conditions per 40 CFR 144.51(e).

10. **Duty to Provide Information:** The Permittee shall furnish to the Director in electronic format, within the time specified by the type of submittal or as defined by the Director, any information that the Director may request to determine whether cause exists for modifying, revoking, and reissuing, or terminating this Permit, or to determine compliance with this Permit or the UIC regulations. The Permittee shall also furnish the Director, upon request within a specified time, with electronic copies of the records required to be kept under this Permit. The Permittee shall also comply with all reporting requirements of this Permit, as specified in Section N - REPORTING AND RECORDKEEPING, and as required by 40 CFR 144.32 and 144.51(h).

11. **Inspection and Entry:** The Permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, under 40 CFR 144.51(i):

    a. Entry upon the Permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records must be kept under the conditions of this Permit;

    b. Have access to and copy, at reasonable times, any records which are required to be kept under the conditions of this Permit;

    c. Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

    d. Sample or monitor, at reasonable times, for the purposes of assuring Permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment, or operations regulated or required under this Permit.

12. **Signatory and Certification Requirements:** All reports, notifications, or any other information, required to be submitted by this Permit or requested by the Director

shall be signed and certified in accordance with 40 CFR 144.32. The Permittee shall ensure that all signed documents include the following certification statement: "*I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.*"

G. AREA OF REVIEW AND CORRECTIVE ACTION

The Permittee shall maintain and comply with the approved Area of Review (AoR) and Corrective Action Plan (CAP) referenced in ATTACHMENT 2: AREA OF REVIEW AND CORRECTIVE ACTION PLAN and shall meet the requirements of 40 CFR 146.84. Under this Permit and UIC regulations, the Permittee shall do the following:

1. The AoR is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream, based on available site characterization, monitoring, and operational data. The Permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan, which is an enforceable condition of this Permit and shall meet the requirements of 40 CFR 146.84.

2. As outlined in ATTACHMENT 2: AREA OF REVIEW AND CORRECTIVE ACTION PLAN, two wellbores within the AoR require plugging because they penetrate the injection zone or confining layer and will not be used for injection or monitoring purposes within the storage project. The wells are required to be properly plugged and abandoned before authorization of carbon dioxide injection (40 CFR 146.84(d)). The Permittee must provide notice in an electronic format 30 days prior to plugging the wells and must allow the Director or their representative an opportunity to attend.

3. At least sixty (60) days before commencing corrective action, the Permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not begin any corrective action until the procedures are approved by the Director, if not already submitted and approved (40 CFR 146.82(a)(13)).

    a. As corrective action activities are completed, the Permittee shall provide the Director with periodic updates, including, as requested, plugging reports.

    b. Corrective action on all deficient wells in the AoR must be complete and approved in writing by EPA before the Permittee may commence injection pursuant to Section R - COMMENCING INJECTION of this Permit and 40 CFR 146.82(c)(6).

4. At a minimum frequency not to exceed every 5 years as specified in the AoR and CAP, or per EPA's decision, more frequently when monitoring and operational conditions warrant, the Permittee must reevaluate the AoR and perform corrective action in the manner specified in 40 CFR 146.84 and update the AoR and CAP or demonstrate to the Director that no update is needed. Reevaluation of the AoR and CAP must meet the requirements of 40 CFR 146.84(e) and must include a new survey of wells identifying the names and locations of all wells within the existing or modified AoR.

5. Following each AoR reevaluation, the Permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and CAP or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan must be incorporated into this Permit as an enforceable condition of this Permit and is subject to the Permit modification requirements at 40 CFR 144.39, 144.41, and 146.84(e)(4). If the Director does not approve the revised AoR and Corrective Action Plan, injection operations cannot continue or be resumed.

6. If the Permittee requests an extension to the Permit expiration due to delayed construction, the Director may request information to update the Permit. Depending on the conditions of the delay, the Director may require a Permit modification.

H. FINANCIAL RESPONSIBILITY

The Permittee must demonstrate and maintain financial responsibility under 40 CFR 146.85 to cover estimated costs. The approved financial responsibility documents and estimated costs for this Permit are included as ATTACHMENT 3: FINANCIAL RESPONSIBILITY DEMONSTRATION of this Permit. The Permittee must submit qualifying financial responsibility instrument(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Permittee must provide the Director with any updated information related to their financial responsibility instrument(s) on an annual basis, as well as any changes. The Permittee must comply with financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration. The requirement to maintain adequate financial responsibility and resources is directly enforceable, regardless of whether it is a condition of the Permit.

1. **Cost Estimate Updates and Adjustments**: During the life of the geologic sequestration (GS) project, the Permittee shall maintain a current detailed written

cost estimate to reflect adjustments for inflation costs and any amendments made to the Project Plans included as Attachments of this Permit. The Permittee shall submit updates, adjustments, and amendments to the cost estimates as follows:

a. Annually, within 60 days prior to the anniversary date of the establishment of the financial instrument. This estimate must account for annual inflation

b. Within 60 days of any amendment 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/or the emergency and remedial response plan (40 CFR 146.94).

c. No later than 60 days after the Director has approved the request to modify 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/or the emergency and remedial response plan (40 CFR 146.94), if the change in the plan increases the cost.

d. Within 60 days of notification from the Director that the most recent financial responsibility demonstration is no longer adequate to cover the current estimated costs.

e. Cost estimates must be based on the costs of hiring a third-party independent of the Permittee's corporate structure to perform the required activities.

f. The Permittee must obtain approval from the Director for any new or updated cost estimate or revised financial instrument. The Permittee shall submit qualifying revised financial responsibility instrument(s) that cover the new or updated costs within 60 days of any amendment(s).

g. The Permittee must obtain approval from the Director to decrease the value of the financial assurance instrument or withdraw funds if a change to the plans results in a decrease in cost.

2. **Adverse Financial Conditions Notification***:* Pursuant to 40 CFR 146.85(d), the Permittee shall notify the Director by certified mail and email of any adverse financial conditions that may affect their ability to cover current cost estimates.

   a. **Bankruptcy and/or Insolvency of the Permittee**: If the Permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the Permittee shall notify the Director within 10 days after commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the Permittee as the debtor. A guarantor of a corporate guarantee must make such a notification if he or she is named as debtor, as required under the terms of the guarantee. Within 60 days of notification from the Director that the most recent financial responsibility demonstration is no longer adequate to cover the current estimated costs.

b. **Bankruptcy, Insolvency, Suspension, or Loss of Authority of an Issuing Financial Institution**: In the event of insolvency or bankruptcy of the trustee or issuing institution of the financial mechanism; the suspension or revocation of the authority of the trustee institution to act as trustee; or the issuing institution's losing its authority to issue such an instrument: The Permittee must notify the Director within 10 business days of the Permittee receiving notice of such event. A Permittee who obtains a letter of credit, surety bond, or insurance policy will be deemed to be without the required Financial Responsibility or liability coverage in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution. The Permittee must establish other financial responsibility or liability coverage acceptable to the Director, within 60 calendar days after such an event.

3. **Changes in Coverage**: Whenever a cost estimate increases to an amount greater than the face amount of a controlling financial instrument, the Permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other qualifying financial responsibility instruments to cover the increase. Inability to provide full financial coverage will result in termination of the Permit. Whenever a current cost estimate decreases to an amount less than the face amount of a controlling financial instrument, the face amount of the financial assurance. Instrument may be reduced to the amount of the current cost estimate only after the Permittee has received written approval from the Director. (40 CFR 146.85(c)(4)).

I. WELL CONSTRUCTION REQUIREMENTS

The requirements listed in this section outline the approved and required construction standards per 40 CFR 146.86. The full Permit application includes a more detailed EPA-approved design and specifications for the injection well, injection zone monitoring wells, confining zone monitoring wells, and groundwater monitoring wells that are the subject of this Permit. Additionally, the approved stimulation program for the well is in ATTACHMENT 5: STIMULATION PLAN.

1. **Injection Well Construction:** The well must be constructed in accordance with 40 CFR 146.86. The design and construction must allow continuous monitoring of the annulus between the long string casing and the injection tubing and accommodate testing devices and workover tools. Equipment must be calibrated and maintained per the Permit's Quality Assurance and Surveillance Plan. Any deviations from the proposed design and as-built construction of the well must be noted and approved by the Director in advance.

2. **Siting:** The Permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

3. **Casing and Cementing:** The well must be cased and cemented per 40 CFR 146.82 and 146.86. Casing, cement, or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The well must be cased and cemented to prevent the movement of fluids into or between USDWs for the expected duration of the geologic sequestration project in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in ATTACHMENT 4: CONSTRUCTION DETAILS of this Permit and in the application for this Permit.

4. **Injection Tubing and Packer:** The tubing and packer design must meet the requirements of 40 CFR 146.86(c). Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. Injection must only take place through the tubing, with a packer set in the long string casing within or below the nearest cemented and impermeable confining system no more than 100 feet above the injection zone. The tubing and packer used in the well are represented in the engineering drawings contained in ATTACHMENT 4: CONSTRUCTION DETAILS of this Permit. Any change must be submitted in an electronic format and approved by the Director before installation.

5. **Sampling and Monitoring Devices:** The Permittee must install and maintain in good condition all devices required to measure, monitor, and record the data and parameters referred to in ATTACHMENT 1: SUMMARY OF OPERATING REQUIREMENTS and ATTACHMENT 6: TESTING AND MONITORING of this Permit per their Quality Assurance and Surveillance Plan. The Permittee must ensure that the devices installed, and methods used are sufficient to represent the activity being measured, monitored, or recorded. For required continuous monitoring, the Permittee must use devices capable of accurately monitoring the required activity. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a backup system if the primary continuous monitoring devices malfunction or become inoperable. The Permittee must notify EPA of such occurrences within 24 hours, and continuous monitoring devices must be repaired or replaced as soon as practicable. If this length of time is extensive, in the opinion of the Director, injection activities must cease until regular monitoring is restored. The Permittee must ensure the well's construction and near-wellhead design are appropriate for collecting samples and fulfilling all monitoring requirements of this Permit. The Permittee must ensure adequate well diameter to

accommodate appropriate tools for well development, aquifer testing equipment, and water quality sampling devices. The Permittee must ensure all gauges used for monitoring and testing are appropriately calibrated and maintained.

6. **Monitoring Well Construction:** 40 CFR 146.84 and 146.90(g) require monitoring of the carbon dioxide plume and pressure front of the confining and injection zones and 40 CFR 146.90(d) requires monitoring of groundwater located above the injection zone. These sections are incorporated by reference into this Permit. Groundwater, confining zone, and injection zone monitoring wells must be constructed as depicted in the application referenced in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit using materials compatible with the injected fluids. All monitoring wells must be constructed in a manner that provides representative samples that can be analyzed for the monitoring parameters required by this Permit. Once the construction of the monitoring wells has been completed, the as- built construction diagrams must be included in the Pre-Injection Testing Report to be submitted to the Director.

J. PRE-INJECTION TESTING

Testing is required during the construction of the well per 40 CFR 146.87. This testing is required to verify the geology of the well site and ensure compliance with the well construction requirements outlined in 40 CFR 146.86, as well as to assess the viability of the well in meeting the stipulated operational requirements. All testing must be conducted in accordance with 40 CFR 146.87 and using the procedures in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit.

1. Prior to receiving authorization to commence injection, the Permittee must perform all pre-injection logging, sampling, testing, and coring specified in 40 CFR 146.87 and submit to the Director for approval a descriptive report that includes a detailed interpretation of the results of such logging, sampling, testing, and coring. At a minimum, this testing must include:

   a. Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests must include:

      i. Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

      ii. Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

      iii. Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

      iv. Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); these tests may include a pressure test with liquid or gas, a casing inspection log, and an approved tracer survey such as an oxygen activation log or a temperature or noise log; and

v. Any alternative methods that are required by and/or approved by the Director pursuant to 40 CFR 146.87(a)(5)

b. Whole cores or sidewall cores of the injection zone confining system, and any other formations as required by the Director, and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b).

c. Documentation of the measured fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s) that meet the requirements of 40 CFR 146.87(c).

d. Tests to determine well-specific data regarding the injection and confining zones. These tests must determine fracture pressure, the physical and chemical characteristics of the injection and confining zones, and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(b)-(d).

e. Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

i. A pressure fall-off test; and

ii. A pump test or injectivity test.

2. The Permittee must submit to the Director for approval in electronic format a schedule for pre-operational testing activities 30 days before conducting the first test and submit any changes to the schedule 30 days before the next scheduled test. The Permittee must also provide the Director with the opportunity to witness all logging, sampling, testing, and coring required under this Section.

K. INJECTION WELL OPERATION

1. **<u>Outermost Casing Injection Prohibition</u>**: Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. **<u>Injection Pressure Limitation</u>:** Except during stimulation or at other specific times as approved by the Director, the Permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) and does not initiate new fractures or propagate existing fractures in the injection zone(s). Per 40 CFR 146.91(c)(2), the Permittee is to notify the EPA within 24 hours of any instances where injection pressure is no longer in compliance with the Permit. Under no circumstances shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The measured maximum allowed bottomhole pressure is based on the interval or stage in which the Permitted well resides, which ranges from 4,620 psi in stage 1 to 2,107 psi in stage 7. The annulus pressure will be adjusted to be more than 100 psi

above the wellhead injection pressure, with a maximum allowable pressure of 2,750 psi. The minimum annulus pressure is 500 psi and is listed in ATTACHMENT 1: SUMMARY OF OPERATING REQUIREMENTS of this Permit. As such, the maximum allowed injection pressure is not to exceed 2,650 psi.

3. **Stimulation Program:** If injection rates decline below expected values at any time during the project life, the Permittee shall investigate the cause to determine whether stimulation may be required. Under 40 CFR 146.91(d)(2), the Permittee must notify the Director in writing 30 days in advance of any planned stimulation activities and obtain prior approval from the Director to conduct stimulation activities and carry out the Stimulation Plan in accordance with the proposed stimulation program outlined in ATTACHMENT 5: STIMULATION PLAN.

4. **Additional Injection Limitations:** No injection fluid other than supercritical CO2 may be injected, except for fluids used for stimulation, rework, and well tests, as approved by the Director. Injection must occur within the injection tubing.

5. **Annulus Fluid:** The Permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential:** Except during workovers or times of annulus maintenance, the Permittee must maintain annulus pressure at least 100 psi greater than the injection pressure as specified in ATTACHMENT 1: SUMMARY OF OPERATING REQUIREMENTS of this Permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Maintenance of Mechanical Integrity**: Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or Permittee must always maintain the injection well's mechanical integrity.

8. **Continuous Recording Devices, Automatic Alarms, and Automatic Shut-Off Systems**:

   a. The Permittee must:

      i. Install and use continuous recording devices to monitor the injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume;

      ii. Install, continuously operate, and maintain an automatic alarm and automatic shut- off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      iii. Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month or as recommended by the equipment manufacturer, whichever is sooner, after the last approved demonstration.

Testing under Section K - INJECTION WELL OPERATION must involve subjecting the system to simulated failure conditions. The Permittee must provide the Director with notice in electronic format at least 30 days prior to running the test and offer the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device that records the value of the parameter of interest or by a service company job record. A final report, including any additional interpretation necessary for the evaluation of the testing, must be submitted in an electronic format within the time period specified in Section N - REPORTING AND RECORDKEEPING of this Permit.

9. **Precautions to Prevent Well Blowouts:** Except at specific times as approved by the Director, the Permittee must maintain a pressure on the well that will prevent the return of the injection fluid to the surface. The well bore must be filled with a fluid of sufficient specific gravity during workovers to maintain a positive (downward) pressure gradient, and/or a plug shall be installed that can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The Permittee must follow procedures such as those below to ensure that a backflow or blowout does not occur at any time during active injection and workovers:

    a. Limit the temperature and/or corrosivity of the injectate; and

    b. Develop procedures necessary to ensure that pressure imbalances do not occur.

10. **Circumstances Under Which Injection Must Cease**: Injection must cease when any of the following circumstances arise:

    a. Failure of the well to pass a mechanical integrity test;

    b. A loss of mechanical integrity during operation;

    c. The automatic alarm or automatic shut-off system is triggered;

    d. An unexpected change, or permitted limitation breach in the annulus or injection pressure occurs;

    e. The Director determines that the well lacks mechanical integrity;

    f. Movement of injection or formation fluids outside of the current, approved injection interval (according to stage) is detected;

    g. Movement of injection or formation fluids outside of previously approved, retired injection interval/stage is detected;

    h. Movement of injection or formation fluids into a USDW is detected;

i. Conditions described in Section Q - SEISMIC EVENT RESPONSE, of this Permit, occur;

j. The Director determines the site is no longer suitable for injection based on new information about the site geology; or

k. The Director determines that the Permittee cannot maintain compliance with any condition of this Permit or regulatory requirement.

In all instances where injection ceases, it must stop immediately, and the Permittee must get approval from the Director to resume injection. If an automatic shutdown (i.e., down-hole or at the surface) is triggered, the Permittee must immediately investigate and identify the cause of the shutdown as expeditiously as possible. If, upon investigation, the well appears to lack mechanical integrity, or if the required monitoring of data from continuous recording devices or automatic shutoff systems indicates that the well may lack mechanical integrity, the Permittee must take the actions listed below in Section L - MECHANICAL INTEGRITY of this Permit.

L. MECHANICAL INTEGRITY

The Permittee must ensure that the injection well and all other wells covered by this Permit have both internal (no significant leaks in the casing, tubing, and packer) and external (no significant fluid movement outside of the injection zone) mechanical integrity for the entire operational life of the well. The required tests and test procedures for mechanical integrity are referred to in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit.

1. **Standards:** Other than during periods of well workover (repair or maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. The Permittee must demonstrate mechanical integrity using the approved tests and test procedures in ATTACHMENT 6: TESTING AND MONITORING PLAN. The Permittee must also conduct any additional testing as the Director may require to make this determination. The determination of whether the injection well has mechanical integrity is at the discretion of the Director.

2. **Mechanical Integrity Demonstration Requirements and Schedule:**

   a. The Permittee must demonstrate internal and external mechanical integrity as follows.

      i. After well construction is completed using tests listed in Section J.1.(a)(iv) - PRE-INJECTION TESTING) of this Permit.

      ii. Continuous monitoring of pressure on the annulus between the tubing and the long string casing to demonstrate internal mechanical integrity.

iii. Annually for external mechanical integrity using a method listed in 40 CFR 146.89(c).

iv. Any test with a greater than 3% pressure differential will be deemed as failed per 40 CFR 146.89(f).

v. After any loss or suspected loss of mechanical integrity.

vi. Demonstrate internal mechanical integrity annually and after any well alteration, repair, or workover that may compromise the internal mechanical integrity of the well, including well stimulation and injection in a different injection interval/stage.

vii. Demonstrate external mechanical integrity prior to plugging the well pursuant to 40 CFR 146.92(a) and as listed in ATTACHMENT 7: WELL PLUGGING PLAN of this Permit.

viii. After a seismic event as Section Q - SEISMIC EVENT RESPONSE of this Permit outlines.

ix. Any time upon written request from the Director.

b. The Permittee must obtain written authorization from the Director prior to commencing/resuming injection in any of the circumstances listed in Section R - COMMENCING INJECTION.

3. **Monitoring Wells:** The Testing and Monitoring Plan referenced in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit outlines required mechanical integrity tests and procedures for the confining zone and injection zone monitoring wells. Testing and demonstration of monitoring wells must be conducted annually. The Director can consider other tests and/or procedures not listed in this plan for approval.

4. **Alternative Mechanical Integrity Tests and Procedures:** The Permittee must submit any proposed alternative tests and/or procedures not listed in this Permit to EPA for approval prior to using them to demonstrate mechanical integrity.

5. **EPA Witnessing of Mechanical Integrity Tests:** The Permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. To conduct testing without an EPA witness, the Permittee must adhere to the following procedures:

   a. Submit prior notice in an electronic format to the Director at least 30 days prior to the test, including the information that no EPA representative is available;

   b. Perform the test in accordance with the Testing and Monitoring Plan found in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit and document the test using either a mechanical or digital device that records the value of the parameter of interest; and

c. Within 30 days of the test, submit a final report, including any additional interpretation necessary for evaluating the testing, a test record(s), and gauge certification(s), in electronic format to the Director for approval.

6. **Gauge and Meter Calibration:** Prior to testing, the Permittee must ensure proper calibration of all gauges used in mechanical integrity demonstrations and other monitoring required by this Permit. All equipment must be calibrated in the manner and frequency recommended by the manufacturer and within at least one year prior to each required test. The date of the most recent calibration must be noted on or near the gauge or meter. A copy of the calibration certificate(s) must be submitted to the Director in electronic format with the final report. All recordings must record to an accuracy of no more than 0.5 percent of full scale for mechanical gauges. Pressure gauge resolution must be no greater than five psi. Additionally, specific mechanical integrity tests and other testing may require greater accuracy and must be identified in the procedure submitted to the Director prior to the test.

7. Notification prior to Testing and Reporting:

    a. The Permittee must notify the Director in an electronic format of intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

    b. The Permittee must notify the Director of any loss or suspected loss of mechanical integrity following the procedures in Section N - REPORTING AND RECORDKEEPING of this Permit.

    c. The Permittee must report in an electronic format the results of a mechanical integrity demonstration as soon as possible but no later than 30 days after the demonstration is complete. Reports of mechanical integrity demonstrations, which include logs, must include an interpretation of results by a knowledgeable log analyst.

8. **Loss of Mechanical Integrity**: If the Permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the Permittee must:

    a. Cease injection immediately;

    b. Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of potential USDW endangerment, the Emergency and Remedial Response Plan referenced by ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN, must be implemented;

    c. Within 24 hours of the event, notify the Director of the circumstances surrounding the event;

d. Notify the Director in an electronic format when injection can be expected to resume and submit a projected plan for reestablishing mechanical integrity or plugging the well within 60 days of the loss of mechanical integrity for EPA approval. The Permittee must initiate plugging or repair activities within 30 days of EPA approval or an alternative timeline approved by EPA;

e. Follow any other applicable reporting requirements as directed in Section N - REPORTING AND RECORDKEEPING of this Permit;

f. Restore and demonstrate mechanical integrity to the satisfaction of the Director within the EPA-approved timeline and receive written approval from the Director prior to resuming injection. The Permittee shall not resume injection without EPA approval; and

g. Either plug or repair and retest the well within 30 days of losing mechanical integrity if the well loses mechanical integrity prior to the next scheduled test date.

M. TESTING AND MONITORING

The required specific measurement and reporting frequencies for testing and monitoring activities are listed in ATTACHMENT 6: TESTING AND MONITORING PLAN. Sampling parameters, sampling handling and custody, quality control, and quality assurance will be performed as described in Appendix E: Quality Assurance and Surveillance Plan in ExxonMobil's application, which is partly documented in the tables below.

1. **Testing and Monitoring Plan:** The Permittee must maintain and comply with the approved Testing and Monitoring Plan referenced in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit and with the requirements within 40 CFR 144.51(j), 146.88(e), and 146.90, and any modifications required by the Director after the effective date of this Permit. Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity. Procedures for all testing and monitoring under this Permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test, if they plan to deviate from the procedures outlined in the Testing and Monitoring Plan referenced in ATTACHMENT 6: TESTING AND MONITORING PLAN of this Permit and detailed in the Quality Assurance and Surveillance Plan. The final report must be delivered to the Director 30 days after testing. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take appropriate action, including but not limited to requiring the Permittee to re-run the test.

   The Permittee must update the Testing and Monitoring Plan as required by 40 CFR 146.90(j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G - AREA OF REVIEW AND CORRECTIVE

ACTION of this Permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration must be submitted to the Director in an electronic format within one year of an AoR reevaluation following any significant changes to the facility, such as the addition of monitoring wells or newly permitted injection wells within the AoR or when required by the Director.

Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the Permittee must submit the resultant information in an electronic format to the Director for review and approval of the results. Revisions to the Testing and Monitoring Plan must be approved by the Director, must be incorporated into this Permit, and are subject to the modification requirements at 40 CFR 144.39 or 40 CFR 144.41, as appropriate.

2. **Carbon Dioxide Stream Analysis:** The Permittee must analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the approved Testing and Monitoring Plan, and to meet the requirements of 40 CFR 146.90(a). Samples of CO2 will be obtained at a sample port on the Project's central pad. The central pad is the connection point between the CO2 pipeline and the sequestration field's distribution system.

Pressure Field Gauge – Central Injection Pad (PIT 52079 & PIT 52088)

Parameter	Value
Calibrated working pressure range	0 to 4000 psig
Initial pressure accuracy	+/-0.04% of span (1.6 psig)
Pressure resolution	+/- 0.000061% of span (0.244 psig)
Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years
psig = pounds per square inch gauge	

Summary of Sample Containers, Preservation Treatments, and Holding Times for CO2 Gas Stream Analysis

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample cooler/cabinet	5 days
cc = cubic centimeter; L = liter			

Summary of Analytical Parameters for CO2 Stream

Parameters[1]	Analytical Methods[2]	Detection Limit/Range	Typical Precisions
Oxygen	ISBT 4.0, GC/DID or Method 3A	1 µL/L to 30 µL/L (ppm v/v)	± 10% reading
Nitrogen	ISBT 4.0, GC/DID or by difference	1 + µL/L (ppm v/v)	± 10% reading
Carbon monoxide	ISBT 5.0, GC/DID	1 µL/L to 10 µL/L (ppm v/v)	± 10% reading
Oxides of nitrogen	ISBT 7.0	0.5 µL/L to 5 µL/L (ppm v/v)	± 20% reading
Total hydrocarbons	ISBT 10.0, GC	1 µL/L to 50 µL/L (ppm v/v)	5-10% of reading
Methane	ISBT 10.1, GC	1 µL/L to 50 µL/L (ppm v/v)	5-10% of reading
Sulfur dioxide	ISBT 14.0, GC	0.05 µL/L to 1.0 µL/L (ppm v/v)	5-10% of reading
Hydrogen sulfide	ISBT 14.0, GC	0.01 µL/L to 0.1 µL/L (ppm v/v)	5-10% of reading
CO2 purity	ISBT 2.0, GC/DID or Method 3A	5.0% to 99.9%	± 10 % of reading
Water	ISBT 3.0, GC/FTIR, Method 320, EPA Method 4	1.0% to 99.9%	± 10 % of reading
µL/L = microliters per liter; DID = Discharge Ionization Detector; FTIR = Fourier Transform Infrared Spectroscopy; GC = gas chromatography; ISBT = Internation Society of Beverage Technologists; ppm = parts per million; v/v = volume/volume			

3. **Continuous Monitoring:** The Permittee must install and use continuous recording devices to monitor: the injection pressure (at the surface and at injection interval), injection flow rate, injection mass, pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature (at the surface and at injection interval). This monitoring must be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The Permittee must maintain for EPA's inspection at the facility an appropriately scaled, continuous record of all monitoring results as well as original files of any digitally recorded information pertaining to these operations. Additionally, refer to the Table below, “Summary of Testing and Monitoring Plan,” for details regarding continuous monitoring.

Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency

Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Pressure Gauge	Annulus System Tank	5 seconds	5 minutes
CO2 stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word "continuous" is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected "continuously" will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Summary of Measurement Parameters for Field Gauges

Equipment/Location	Parameter	Value
Pressure Field Gauge – Pressure Gauge (PIT 52127 Upstream of Choke)	Calibrated working pressure range	0 to 3,000 psig
	Initial pressure accuracy	+/-0.04% of span (1.2 psig)
	Pressure resolution	+/- 0.000061% of span (0.183 psig)
	Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years
Pressure Field Gauge – Wellhead Pressure Gauge (PIT 52136B D/S of Choke)	Calibrated working pressure range	0 to 3,000 psig
	Initial pressure accuracy	+/-0.04% of span (1.2 psig)
	Pressure resolution	+/- 0.000061% of span (0.183 psig)
	Pressure drift stability	0.2% of upper range limit (8 psig) for 10 years

Pressure Field Gauge – Downhole Pressure Gauge	Calibrated working pressure range	200 to 10,000 psi
	Initial pressure accuracy	0.015 psi
	Pressure resolution	0.006 psi/sec
	Pressure drift stability	0.02 psi/year at max pressure and temperature
Temperature Field Gauge – Downhole Temperature Gauge	Calibrated working temperature range	25 to 150 °C
	Initial temperature accuracy	0.5 °C
	Temperature resolution	0.005 °C/sec
	Temperature drift stability	0.1 °C/year at max temperature
Mass Flow Rate Field Gauge – Coriolis Meter at Central Injection Pad	Calibrated working flow rate range	0 to 200,000 kg/hr
	Initial mass flow rate accuracy	+/-0.1% of rate
	Mass flow rate resolution	Pulses +/-50 ppm
	Mass flow rate drift stability	At Central Injection Pad: Zero Point Stability – 32 kg/hr for At Well Pad: Zero Point Stability – 14 kg/hr
	Calibrated working temperature range	0 to 300 °F
	Initial temperature accuracy	0.06 °F
Pre-Injection Temperature Transmitter	Temperature resolution	0.000183 °F
	Temperature drift stability	+/-0.1% of reading or 0.18 °F whichever is greater for two years
°C = degrees Celsius; °F = degrees Fahrenheit; kg/hr = kilograms per hour; ppm = parts per million; psi = pounds per square inch; psig = pounds per square inch gauge; sec = second;		

Downhole Pressure and Temperature Gauge Specifications

Parameter	Value
Calibrated working pressure range	200 to 10,000 psi
Initial pressure accuracy	0.015 psi
Pressure resolution	0.006 psi/sec

Pressure drift stability	0.02 psi/year at max pressure and temperature
Calibrated working temperature range	25–150 °C
Initial temperature accuracy	0.5 °C
Temperature resolution	0.005 °C/sec
Temperature drift stability	0.1 °C/year at 177 °C
Max temperature	177 °C
Instrument calibration frequency	Per manufacturer's specifications
psi = pounds per square inch	

Downhole Pressure and Temperature Gauge Specifications

Parameter	Logging Speed	Vertical Resolution	Temp. Rating	Pressure Rating
Distributed Temperature Sensing	12 seconds	0.5-meter	-82–177°C	Not Applicable

4. **<u>Corrosion Monitoring</u>:** The Permittee must perform quarterly corrosion monitoring of the construction materials in all pipeline, injectors, above zone monitor and UDW water wells for loss of mass, thickness, cracking, pitting, and other signs of corrosion using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c). This ensures that the well components meet the minimum standards for material strength and performance outlined in 40 CFR 146.86(b). Additionally, see the Table below – "Summary of Testing and Monitoring Plan."

Summary of Analytical Parameters for Corrosion Coupons

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass and Thickness	Baseline: ASTM G1-03(2017)e1 After Baseline: AMPP NACE SP0775-2023	± 0.2 mg	± 1%	Laboratory equipment calibration to manufacturer's specification
ASTM = American Society for Testing and Materials; AMPP = Association for Materials Protection and Performance; NACE = National Association of Corrosion Engineers				

5. **<u>Groundwater Monitoring Above the Confining Zone</u>:** The Permittee shall monitor groundwater quality and geochemical changes above the confining zone that may be a result of carbon dioxide movement through the confining zone and additional identified geologic units. All monitoring conducted must be performed for the parameters identified in the approved Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d). Additionally, see the Table below – "Summary of Monitoring Techniques for Direct and Indirect CO2 Plume and Pressure Front Tracking."

USDW and Above UCCZ Monitoring Sampling Program

Parameter/Analyte	USDW Monitoring Well Frequency	Monitoring Frequency above the UCCZ
TDS, alkalinity, electrical conductivity, temperature, pH	Quarterly	Quarterly
Gas composition (CO2, CH4, O2, N2)		
Dissolved cations (Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn)		
Dissolved anions (HCO3, B(OH)4, Br, CO3, Cl, F, I, NO3, NO2, PO4, SO4, S)		
Note: Ba = Barium; B(OH)4 = Tetrahydroxyborate; Br = Bromide; Ca = Calcium; Cd = Cadmium; CH4 = Methane; Cl = Chloride; CO2 = Carbon dioxide; CO3 = Carbonate; Co = Cobalt; Cr = Chromium; Cu = Copper; F = Fluoride; Fe = Iron; HCO3 = Bicarbonate; I = Iodide; Li = Lithium; Mg = Magnesium; Mn = Manganese; Mo = Molybdenum; N2 = Nitrogen; Na = Sodium; Ni = Nickel; NO2 = Nitrite; NO3 = Nitrate; O2 = Oxygen; P = Phosphorus; K = Potassium; PO4 = Phosphate; Si = Silicon; SO4 = Sulfate; Sr = Strontium; S = Sulfur; TDS = Total Dissolved Solids; V = Vanadium; Zn = Zinc		

Field Stabilization Criteria for USDW Well Sampling

Field Parameter	Stabilization Criteria
pH	±0.2 units
Temperature	±3%
Specific conductance	±3%
Dissolved oxygen	±10%
Turbidity	Stabilized or <10 NTUs
NTU = nephelometric turbidity unit	

Summary of Analytical and Field Parameters for Fluid Samples in USDW and Above UCCZ

Parameters	Analytical Methods [1,2]	Typical Detection Limit or Range [3]	Typical Precisions [3]	QC Requirements [2]

Dissolved Cations: Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn	EPA Method 6020A	0.001 to 0.1 mg/L [4]	±15%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Dissolved Anions: HCO3, B(OH)4, Br, CO3, Cl, F, I, NO3, NO2, PO4, SO4, S	EPA Method 300.0	0.001 to 0.1 mg/L [4]	±15%	
Total dissolved solids	Method SM 2540C	10 mg/L	±5%	
Alkalinity Bicarbonate (HCO3)	Method SM 2320B	2 mg/L	±10%	
pH (field)	Field measurement	0–14 pH [5]	±0.1	Factory calibration and user calibration per manufacturer's instructions, duplicates
Electrical conductivity (field)	Field measurement	0–100 mS/cm [5]	±1%	
Temperature (field)	Field measurement	-10 to -55 °C [5]	±0.10	
Dissolved Oxygen (field)	Field measurement	0-50 mg/L	±0.10 mg/L	
Gas composition (CO2)	RSK-175 or ASTM D513-16 [6] depending on laboratory availability	0.1 µg/L	±15%	Daily calibration: blanks, duplicates, and matrix spikes at 10% or greater frequency
Gas composition (CH4)	RSK-175	0.1 µg/L	±15%	
Gas composition (N2)	TKN Method 351.2; Nitrite/Nitrate 353.2; or RSK-175 depending on laboratory availability	0.1 mg N	±15%	

Notes:

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

2. The listed analytical methods and QC requirements may be revised based on input from the accredited laboratories or field instrumentation selected to do the work.

3. The exact detection limit, range, and precision can vary depending on the sample matrix and the conditions under which the analysis is performed. Precision may also be affected by equipment utilized in analytical procedures by laboratory.

4. Analyte, dilution, and matrix dependent.

5. Dependent on manufacturer specification and calibrated range.

6. ASTM 2017b

µg/L = micrograms per liter; mg N = milligrams nitrogen; mS/cm = milliSiemens per centimeter;

Containers, preservation techniques and holding times for groundwater sample parameters collected in the USDW Monitoring Well No. 01, USDW Monitoring Well No. 02, and USDW Monitoring Well No. 03 and from the first water-bearing zone above the UCCZ at Above-Zone Monitor Well No. 01.

Summary of Sample Containers, Preservation Treatments, and Holding Times for Groundwater Samples

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
EPA Method 6020A Dissolved cations (Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn)	1 liter, plastic	0–6 °C	60 days
EPA Method 300.0 Dissolved anions (HCO3, B(OH)4, Br, CO3, Cl, F, I, NO3, NO2, PO4, SO4, S)	1 liter, plastic	0–6 °C	28 days
Method SM 2540C Total Dissolved Solids	1 liter, plastic	0–6 °C	7 days
Method SM 2320B Alkalinity Bicarbonate (HCO3)	500 mL, plastic	0–6 °C	7 days
RSK-175 Gas composition (CO2)	Three 40 mL VOA vials	0–6 °C	14 days
RSK-175 Gas composition (CH4)	Two 40 mL VOA vials	0–6 °C, hydrochloric acid	14 days
Calculated from TKN Method 351.2 Nitrite/Nitrate 353.2	Three 250 mL, plastic	0–6 °C, sulfuric acid	48 hours
Field Methods: Electrical Conductivity, Temperature, pH, DO, ORP, turbidity	Field measurement	Not Applicable	Not Applicable
Note: The listed sample container sizes and preservation techniques may be revised based on input from the accredited laboratory selected to do the work. DO = dissolved oxygen; ORP = oxidation-reduction potential; VOA = Volatile Organic Analysis			

Field QC of groundwater

QC Sample Type	Frequency
Field Duplicate	At least one sample per sample group or 10% for sample sizes above 20 samples

6. **External Mechanical Integrity Testing:** The Permittee must demonstrate external mechanical integrity annually as described in the approved Testing and Monitoring Plan and must comply with Section L -MECHANICAL INTEGRITY of this Permit to meet the requirements of 40 CFR 146.89 and 146.90. Additionally, see the Table below – "Summary of Testing and Monitoring Plan" for details regarding Internal and External Mechanical Integrity Monitoring.

Representative Logging Tool Specifications

Parameter	Logging Speed	Vertical Resolution	Acquired Data	Temp Rating	Pressure Rating
Ultrasonic Casing/ Cement Inspection	400 to 4,500 ft/hr	0.3 to 6.0 in	Image of casing and cement throughout well completion	350 °F	20,000 psi
Electromagnetic	600 to 900 ft/hr	Tubular Defect Location and Resolution: • First Tubular: 1 ft • Second Tubular: 2 ft • Third Tubular: 3 ft • Fourth Tubular: 4 ft • Fifth Tubular: 4 ft	Electromagnetic log of casing thickness	350 °F	15,000 psi
Cement Bond Log	Up to 3,600 ft/hr	3 ft	Image of cement between casing and formation	350 °F	20,000 psi
Caliper	1800 to 3600 ft/hr	0.12 in	Log of inside diameter of casing	350 °F	20,000 psi
Temperature Log	NA	1.2 in to 6 in depending on sampling rate	Vertical temperature profile of well	350°F	20,000 psi
°F = degrees Fahrenheit; ft = foot; ft/hr = feet per hour; in = inch; NA= not applicable; psi = pounds per square inch					

7. **Casing Inspection Logs:** Casing inspection logs shall be run whenever the owner or Permittee conducts a workover in which the injection string is pulled unless the Director waives this requirement due to well construction or other factors that limit the test's reliability or based upon the satisfactory results of a casing inspection log run within the previous five years. The Director may require that a casing inspection log be conducted annually if the Director has reason to believe that the integrity of the long string casing of the well may be adversely affected by naturally occurring or human-induced events. If corrosion coupon data indicates a potential loss of material strength or performance inconsistent with operating standards, the Permittee shall report this to the Director within 24 hours and complete a casing inspection log.

8. **Pressure Fall-Off Test:** The Permittee shall conduct a pressure fall-off test at least once every five years unless the Director requires more frequent testing based on site- specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f). See Pressure Fall-Off Testing in the Table below – "Summary of Testing and Monitoring Plan." Notable changes in reservoir properties may dictate that an AoR reevaluation is necessary.

Measurement	Purpose	Location(s)	Project Phase & Frequency			Descriptive Features in QASP		
			Pre-Injection	Operation	Post-Injection Site Care	Data Source Type	Method of Data Acquisition	Lab/Custody Procedures
Pressure Fall-Off Testing	Assess injection well performance and formation permeability	Injection Wells No. 01, No. 02, and No. 03	NA	At end of each injection stage	None	Downhole tubing mounted pressure and temperature gauge	Direct Measurement	None
DTS = distributed temperature sensing; NA= not applicable; OA = Wireline deployed oxygen activation (OA) log; P&A = plug and abandon; UCCZ = upper composite confining zone; AoR = Area of Review								

9. **Carbon Dioxide Plume and Pressure Front Tracking**: The Permittee must track the extent of the carbon dioxide plume and pressure front once injection begins, using direct and indirect monitoring methods as described in the approved Testing and Monitoring Plan and in accordance with 40 CFR 146.90(g). The Permittee is required to conduct this monitoring to detect and locate the carbon dioxide pressure front and the dissolved carbon dioxide plume and the data will be used to calibrate the AoR model to determine whether modifications to the AoR need to be made. The data collected will be used to monitor the location of the plume and pressure front, evaluate its movement through time, and compare it to the plume and pressure front predictions of the AoR model. See direct and indirect methods of tracking the

CO_2 plume and pressure front in the Table below – "Summary of Testing and Monitoring Plan."

1. **Direct Methods:** The Permittee must use the deep monitoring well to continuously record the pressure and temperature of the injection zone formation to track the position of the carbon dioxide pressure front, collect fluid samples from the injection zone formation to track the position of the carbon dioxide plume described in the approved Testing and Monitoring Plan, and meet the requirements of 40 CFR 146.90(g)(1). Additionally, see the Table below – "Summary of Monitoring Techniques for Direct and Indirect CO_2 Plume and Pressure Front Tracking."

2. **Indirect Methods:** The Permittee must use indirect monitoring methods to track the position of the carbon dioxide plume and pressure front as described in the approved Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2). See table below - "Summary of Monitoring Techniques for Direct and Indirect CO_2 Plume and Pressure Front Tracking." However, the EPA will require ExxonMobil to initiate the surface seismic events listed at a frequency that coincides with ExxonMobil's planned interval/stage changes. Specifically, "Events #2 and #3," which would allow for a total of 3 surveys within the first 5 years before the first AoR re-evaluation. The data from these surveys will aid in the reevaluation process, enabling the EPA to consider reducing or increasing the surface seismic survey frequency more effectively.

10. **Additional Monitoring:** If required by the Director as provided in 40 CFR 146.90(i), the Permittee must perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 146.86(a). This monitoring must be performed as described in a modification to the Testing and Monitoring Plan.

    a. The Permittee will deploy a seismometer monitoring network to determine the locations, magnitudes, and focal mechanisms of any injection-induced seismic events in case they occur. This information will be used to address public concerns and to monitor changes in induced seismicity risks by adjusting well operations as needed in response to perceived risks.

Summary of Monitoring Technologies for Direct and Indirect CO2 Plume and Pressure Front Tracking

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 40 CFR 146.90(g)(1)	Downhole tubing mounted pressure and temperature gauge	Injection Wells No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval Annual pressure fall-off test during well shut-ins	Identify pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure/ temperature gauges	In-Zone Monitorin g Well No. 01	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring	CO2 plume and pressure front tracking

	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO2 Plume Area	Four injection intervals in the Upper Frio and Fleming Formations	No	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after injection, Survey Event #3 within six to eight years after injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	Monitor CO2 plume growth in the subsurface over time

		Passive Seismicity Monitor Station Array	Selected locations within AoR	Surface	Yes, contingent on triggering seismic event above threshold level determined by Table 8-3: Response Actions for Seismic Events.	Continuous monitoring	AoR-specific seismicity data collection and event analyses
Above UCCZ	Direct per 40 CFR 146.90(g)(1)	Fluid sampling protocol using converted Bead Farm Co. #1 collected through tubing	Above-Zone Monitoring Well - Bead Farm Co. #1	First laterally continuous water-bearing zone above UCCZ	No	Quarterly samples	Detection monitoring for CO2 plume and/or brine crossflow from injection zones to top of UCCZ

	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	From surface to base of Frio Sand 2	No.	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after injection, Survey Event #3 within six to eight years of injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary during PISC, as approved by UIC Program Director.	Detection monitoring for presence of CO_2 plume above UCCZ Detection monitoring and evaluation of trends in water quality and geotechnical parameters

USDW	Direct per 40 CFR 146.90(d)	Fluid Sampling	USDW Monitoring Wells No. 01, No. 02, No. 03	Groundwater samples collected just below the typical total depth of water wells completed in the area (e.g., 300 to 350 ft BGL).	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO2 plume and pressure front tracking as discussed in AoR reevaluations	Pre-Operational Phase – Quarterly Operational Phase – Quarterly	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil Gas Monitoring	Direct per 40 CFR 146.90(h)	Soil gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Direct per 40 CFR 146.90(h)	Portable and/or stationary CO2 detectors monitor record ambient CO2 concentrations	Contingent on confirmed release to USDW				

Summary of Testing and Monitoring Plan

	Purpose	Location(s)	Project Phase & Frequency			Descriptive Features in QASP		
			Pre-Injection	Operation	Post-Injection Site Care	Data Source Type	Method of Data Acquisition	Lab/Custody Procedures

Carbon Dioxide Stream Analysis	CO2 stream composition	Central Pad	Baseline	Quarterly	NA	One sample per quarter	Chemical Analysis	Accredited laboratory receiving samples under chain-of-custody
Carbon Dioxide Stream Temperature	Monitor injection temperature	Central Pad	Baseline	Continuous	NA	Coriolis meter/wellhead pressure logger	Direct Measurement	None
Injection Rate, Density, and Mass	Rate and volume monitoring	Central Pad	NA	Continuous	NA	Coriolis meter	Direct Measurement	None
Injection Pressure	Compliance with operating permit	Surface, injection well piping	NA	Continuous	NA	Pressure gauge at central injection pad	Direct Measurement	None
Annular Pressure	Pressure monitoring and well integrity	Injection Wells	NA	Continuous	NA	Pressure gauge	Direct Measurement	None
Corrosion Monitoring	Well Integrity	Central Pad downstream of metering skid	NA	Quarterly	NA	Corrosion coupon	Physical Analysis	Accredited laboratory receiving samples under chain-of-custody

Internal Mechanical Integrity – Injection Tubing	Well Integrity	Injection Wells No. 01, No. 02, and No. 03	Baseline	Continuous	Prior to P&A	Tubing annulus pressure measured at surface of wellhead	Direct Measurement	None
External Mechanical Integrity	Well Integrity	Injection Wells No. 01, No. 02, and No. 03	Baseline	Continuous Annual (surveys)	Prior to P&A	DTS Temperature surveys Pulse Neutron Log in OA mode	Direct Measurement	None
Containment and Control	Assess CO_2 plume and brine pressure front Containment below UCCZ	USDW Monitoring Wells No. 01, No. 02, No. 03 Above-Zone Monitoring Well No. 01 (Bead Farm Co. #1)	Baseline	Quarterly	Annual	One sample per well	Direct Measurement	Accredited laboratory receiving samples under chain-of-custody

Direct CO_2 Plume/Pressure Front Tracking	Demonstrate compliance with permit and calibrate plume model	Injection Wells No. 01, No. 02, and No. 03 In-Zone Monitoring Well No. 01	Baseline	Continuous	Continuous for In-Zone Monitoring Well No. 01	Downhole tubing-mounted pressure and temperature gauge Downhole casing mounted pressure and temperature gauge	Direct Measureme nt	None
Indirect CO_2 Plume/Pressure Front Tracking	Demonstrate compliance with permit and calibrate plume model	Timelapse seismic surveys	Baseline	Two Survey Events	One Survey Event	Surface seismic monitoring	Indirect Measureme nt	None
Indirect CO_2 Plume/Pressure Front Tracking	Demonstrate compliance with permit and calibrate plume model	Surface Seismic sources and receivers near injectors within AoR	Continuo us	Continuous	Continuous	Surface passive seismicity monitoring	Continuous	None

Pressure Fall-Off Testing	Assess injection well performance and formation permeability	Injection Wells No. 01, No. 02, and No. 03	NA	At end of each injection stage	None	Downhole tubing mounted pressure and temperature gauge	Direct Measurement	None
DTS = distributed temperature sensing; NA= not applicable; OA = Wireline deployed oxygen activation (OA) log; P&A = plug and abandon; UCCZ = upper composite confining zone; AoR = Area of Review								

N. REPORTING AND RECORDKEEPING

The Permittee must submit reports at frequencies described in the approved Testing and Monitoring Plan, and as required by this Permit, even when the well is not operating. Reports must contain all the data and information required to be monitored, gathered, and reported by this Permit and meet the requirements of 40 CFR 144.17, 144.51(l), 144.54(c), and 146.91.

1. **Electronic Reporting**: The Permittee must electronically submit all required reports to the GSDT and make and retain all reports, submittals, notifications, records, and correspondence to the EPA made under this Permit in electronic format. Electronic reports, submittals, and records made and maintained by the Permittee under this Permit must be in an electronic format approved by EPA. The Permittee shall electronically submit all required reports to the Director through the Geologic Sequestration Data Tool (GSDT). Required notifications prior to any work, testing, or procedures shall be submitted to R6ClassVI@epa.gov.

2. **Semi-Annual Reports:** The Permittee must submit reports on a semi-annual basis in accordance with 40 CFR 146.91(a). The reporting period for semi-annual reports will be from January 1 through June 30 and from July 1 through December 31. Reports must be submitted within 30 days of the end of each reporting period. Semi-annual reports must include all data collected on a continuous, daily, monthly, quarterly, and semi-annual basis as described in the approved Testing and Monitoring Plan. The second semi-annual report for each year must include all data collected on an annual basis as described in the approved Testing and Monitoring Plan. Reports must contain the following information and data, as well as all other information and data collected not listed below, but as described in the approved Testing and Monitoring Plan or in this Permit:

    a. Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

    b. Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

    c. A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in this Permit;

    d. A description of any event which triggers the shut-off systems required in Section K - INJECTION WELL OPERATION of this Permit pursuant to 40 CFR 146.88(e), and the response taken;

    e. The monthly mass of the carbon dioxide stream injected over the reporting period and the mass injected cumulatively over the life of the project;

    f. Monthly annulus fluid volume added or produced; and

g. Results of the continuous monitoring required in Section M - TESTING AND MONITORING including:

   i. A tabulation of (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily mass of injectate, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and

   ii. Graph(s) of the continuous monitoring as required in Section M - TESTING AND MONITORING of this Permit, or of daily average values of these parameters. The injection pressure, injection mass, flow rate, annulus fluid level, annulus pressure, and temperature must be submitted on one or more graphs, using contrasting symbols or colors or in another manner approved by the Director.

h. Results of any additional monitoring identified in the approved Testing and Monitoring Plan and described in Section M - TESTING AND MONITORING of this Permit.

3. **24-Hour Reporting:**

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a. The Permittee must report to the Director any Permit noncompliance that may endanger human health or the environment and any events that require implementation of actions in the Emergency and Remedial Response Plan referenced by ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN. Any information must be provided within 24 hours from the time the Permittee becomes aware of the circumstances. Such reports must include, but need not be limited to the following information:

   i. Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

   ii. Any noncompliance with a Permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

   iii. Any triggering of the shut-off system required in Section K - INJECTION WELL OPERATION of this Permit (i.e., down-hole or at the surface);

   iv. Any failure to maintain mechanical integrity;

   v. Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere;

vi. Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan referenced by ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN; and

vii. Any change in the status of the well.

b. A written submission must be provided to the Director in an electronic format within five days of the time the Permittee becomes aware of the circumstances described in Section O - WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE of this Permit. The submission must contain a description of the noncompliance, emergency, or remedial response and its cause; the period of noncompliance, emergency, or remedial response, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan referenced in ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN of this Permit; and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance or emergency or condition requiring remedial response.

4. **Reports on Well Tests and Workovers: Report, within 30 days, the results of:**

a. Periodic tests of mechanical integrity;

b. Any well workover, including stimulation;

c. Transitions to different stages.

d. Any other test of the injection well conducted by the Permittee if required by the Director; and

e. Any test of any monitoring well required by this Permit.

5. **Advance Notice Reporting:**

a. **Well Tests:** The Permittee must provide the Director with at least 30 days' advance written notice in electronic format of any planned workover, stimulation, or other well test.

b. **Planned Changes:** The Permittee must provide written notice to the Director in electronic format as soon as possible of any planned physical alterations or additions to the permitted facility, including stage transitions. An analysis of any new injection fluid must be submitted to the Director for review and written approval at least 30 days prior to injection; this approval may result in a Permit modification.

c. **Anticipated Noncompliance:** The Permittee must give at least 14 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity that may result in noncompliance with Permit requirements.

6. **Additional Reports:**

   a. **Compliance Schedules:** The Permittee must submit in electronic format no later than 30 days following each scheduled date reports of compliance or noncompliance with, or any progress reports on, interim and final requirements as contained in any compliance schedule of this Permit.

   b. **Transfer of Permits:** This Permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA. All Financial Responsibility cost estimates, documentation, and instruments, as required by 40 CFR 146.85 and by Section H - FINANCIAL RESPONSIBILITY of this Permit, must be updated and provided to the Director by any new owner of the well.

   c. **Other Noncompliance:** The Permittee must report in an electronic format all other instances of noncompliance not otherwise reported with the following monitoring report. The reports must contain the information listed in Section N - REPORTING AND RECORDKEEPING of this Permit.

   d. **Other Information:** When the Permittee becomes aware of a failure to submit any relevant facts in the Permit application or that incorrect information was submitted in a Permit application or in any report to the Director – including new or changed information about site geology – the Permittee must submit such facts or information in an electronic format within 10 days of discovery per 40 CFR 144.51(l)(8).

   e. **Report on Permit Review:** Within 30 days of receipt of this Permit, the Permittee must certify to the Director in electronic format that he or she has read and is personally familiar with all its terms and conditions.

7. **Records and Record Retention:**

   a. The Permittee must retain records and all monitoring information, including all calibration and maintenance records, all original chart recordings for continuous monitoring instrumentation, and copies of all reports required by this Permit (including records from pre-injection, active injection, and post-injection phases), for at least 10 years from collection.

b. The Permittee must maintain records of all data required to complete the Permit application form for this Permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.31, 144.39, and 144.41 until least 10 years after site closure.

c. The Permittee must retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

d. The retention periods specified in Section N - REPORTING AND RECORDKEEPING of this Permit may be extended at the request of the Director at any time. The Permittee must continue to retain records after the retention period specified in this Section of the Permit or any requested extension thereof expires unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

e. Records of monitoring information must include:

   i. The date, exact place, and time of sampling or measurements;

   ii. The name(s) of the individual(s) who performed the sampling or measurements;

   iii. A precise description of both sampling methodology and the handling of samples;

   iv. The date(s) analyses were performed;

   v. The name(s) of the individual(s) who performed the analyses;

   vi. The analytical techniques or methods used; and

   vii. The results of such analyses.

8. **Signatory and Certification Requirements:** All reports, notifications, or any other information, required to be submitted by this Permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32. The Permittee shall ensure that all signed documents include the following certification statement: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

O. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

The Permittee must maintain and comply with the approved Well Plugging Plan highlighted in ATTACHMENT 7: WELL PLUGGING PLAN and the approved Post Injection Site Care and Site Closure Plan referenced in ATTACHMENT 8: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN and must comply with the requirements of 40 CFR 146.92 and 146.93. The Well Plugging Plan and the Post-Injection Site Care and Site Closure Plan are enforceable conditions of this Permit.

1. **Well Plugging Plan Revisions:** If data indicate and the Permittee deems it necessary, or if the Director requires the approved plans of this Permit to be modified, revised plan(s) must be submitted in an electronic format to the Director for review and written approval. Any amendments to the Well Plugging Plan and/or the Post-Injection Site Care and Site Closure plan must be approved by the Director and must be incorporated into the Permit and are subject to the Permit modification requirements at 40 CFR 144.39 and/or 144.41.

2. **Required Activities Prior to Plugging:** The Permittee must flush the well with an inert buffer fluid, determine the post-injection bottom hole pressure, and perform final internal and external mechanical integrity tests prior to injection well plugging. These tests must be performed as required by Section L - MECHANICAL INTEGRITY of this Permit.

3. **Notice of Plugging and Abandonment:** The Permittee must notify the Director in writing in an electronic format at least 60 days before plugging, conversion, or abandonment of the well, pursuant to 40 CFR 146.92 (c), and must provide the Director or their representative the opportunity to attend. A shorter notice period may be allowed at the discretion of the Director.

4. **Plugging and Abandonment Approval and Report:**

   a. The Permittee must receive written approval from the Director before plugging the well and must plug and abandon the well as required by 40 CFR 146.92, as described in the approved Well Plugging Plan.

   b. Within 60 days after plugging, the Permittee must submit a plugging report to the Director in electronic format. The report must be signed and certified by the Permittee per 40 CFR 144.32 and by the person who performed the plugging operation (if other than the Permittee). The Permittee must retain the well-plugging report in an electronic format for 10 years following site closure. The report must include:

      i. A statement that the well was plugged in accordance with the approved Well Plugging Plan; or

      ii. If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the

Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this Permit may endanger underground sources of drinking water, the Permittee must replug the well as required by the Director.

5. **Temporary Abandonment:** After any 24 consecutive month period of no injection, the well is considered to be in a temporarily abandoned status, and the Permittee must plug and abandon the well following the approved Well Plugging Plan, 40 CFR 144.52 (a)(vi) and 146.92 or make a demonstration of non-endangerment of this well that is satisfactory to the Director while it is in temporary abandonment status. The Director may request multiple demonstrations of non-endangerment while the well is in temporary abandonment status. Temporary abandonment status includes instances where well construction/conversion has begun but the Director has approved no authorization to commence injection. During any periods of temporary abandonment or disuse, the Permittee must continue to comply with the conditions of this Permit, including all monitoring and reporting requirements in compliance with all the requirements of this Permit and all applicable regulations. The Permittee must notify and receive approval from the Director prior to resuming operation of the well.

6. **Post-Injection Site Care and Site Closure Plan:** The Permittee must maintain and comply with the proposed Post-Injection Site Care and Site Closure Plan referenced by ATTACHMENT 8: POST INJECTION SITE CARE AND SITE CLOSURE PLAN of this Permit and comply with the requirements of 40 CFR 146.93. The default post-injection site care period is 50 years, which is an enforceable condition of this permit. If the Permittee elects to propose an alternative post-injection site care period, either within the initial application or at a later date, they will be required to demonstrate that the carbon dioxide injection poses no threat to USDWs.

   a. Upon cessation of injection, the Permittee must demonstrate, through monitoring data and modeling results, that the proposed 50-year post-injection site care period within the Permittee's application requires no amendment or submit an amended Post-Injection Site Care and Site Closure Plan, either which must be submitted in electronic format for the Director's approval.

   b. At any time during the life of the project, the Permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval per 40 CFR 146.93(a)(3). As part of such modifications to the Plan, the Permittee may request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

   c. The monitoring, as outlined in the approved Post-Injection Site Care and Site

Closure Plan, must define the position of the carbon dioxide plume and pressure front, compare the data collected to the predictions made by the AoR model, and demonstrate that USDWs are not being endangered per 40 CFR 146.90 and 146.93.

d. Prior to authorization for site closure, the Permittee must submit to the Director for review and approval, in an electronic format, a demonstration utilizing both monitoring data and modeling results that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b). The Director reserves the right to amend the post-injection site monitoring requirements (including an extension of the monitoring period) if there is a concern that USDWs are at risk of endangerment.

e. The Permittee must notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the previously approved Post- Injection Site Care and Site Closure Plan are proposed, the Permittee must submit a revised plan.

f. After the Director has authorized site closure, the Permittee must plug all monitoring wells as specified in Section O - WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE of this Permit in a manner that will not allow movement of injection or formation fluids to endanger a USDW. The Permittee must also restore the site to its pre-injection condition.

g. The Permittee must submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified in 40 CFR 146.93(f).

h. The Permittee must record a notation on the deed to the facility property or any other document that is normally examined during a title search that will, in perpetuity, provide any potential purchaser of the property the information listed at 40 CFR 146.93(g). The Permittee must retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The Permittee must deliver the records in an electronic format to the Director at the conclusion of the retention period.

P. EMERGENCY AND REMEDIAL RESPONSE

The Emergency and Remedial Response Plan describes actions the Permittee must take to address events that may cause the movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The Permittee must maintain and comply with the approved Emergency and Remedial Response Plan incorporated by reference as ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN of this Permit, which is an enforceable condition of this Permit, and with 40 CFR 146.94. A copy of the Emergency and Remedial Response Plan must be kept on-site at the facility, and staff contact lists must be reviewed annually to confirm contact information is current.

1. If the data collected provides evidence that the carbon dioxide stream and/or pressure front may cause endangerment to a USDW, the Permittee must:

    a. Cease injection per Section K - INJECTION WELL OPERATION and ATTACHMENT 1: SUMMARY OF OPERATING REQUIREMENTS and/or ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN of this Permit;

    b. Take all reasonable steps necessary to identify and characterize any release from the underground injection system;

    c. Notify the Director within 24 hours; and

    d. Implement the approved Emergency and Remedial Response Plan in ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN of this Permit approved by the Director.

2. At the frequency specified in the Area of Review and Corrective Action Plan or more frequently if the monitoring and operational data warrant, the Permittee must review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The Permittee must incorporate monitoring and operational data in AoR reevaluations required under Section G - AREA OF REVIEW AND CORRECTIVE ACTION of this Permit or demonstrate to the Director that no update is needed. In no case shall the owner or Permittee review the Emergency and Remedial Response Plan less often than once every five years. The amended Emergency and Remedial Response Plan or demonstration must be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as, but not limited to, the addition of injection wells, or when required by the Director. If the amendments to the Emergency and Remedial Response Plan cause the cost estimates to change, then a new Financial Responsibility Demonstration must be submitted for review and approval by the Director in accordance with Section H - FINANCIAL RESPONSIBILITY of this Permit.

3. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the Permittee must submit the resultant information in an electronic format to the Director within 30 days for review and confirmation of the results. The Director must review revisions to the Emergency and Remedial Response Plan, which must be incorporated into the

Permit, and are subject to the Permit modification requirements at 40 CFR 144.39 or 40 CFR 144.41, as appropriate.

Q. SEISMIC EVENT RESPONSE

The Permittee shall closely monitor seismic activity and implement a pause to operations or continue operations at a reduced rate should analysis indicate a causal relationship between injection operations and detected seismicity. The Permittee, in consultation with the UIC Program Director, will determine whether immediate or gradual cessation of injection is appropriate.

If seismic events are recorded by either the local private array or a public array (national or state) in the vicinity of the injection well, the Permittee shall implement the response plan subject to detected earthquake magnitude limits defined in the referenced Emergency and Remedial Response plan in ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN to eliminate or reduce the magnitude, frequency and/or effects of seismic events. Consistent with permitting criteria in the State of Texas for injection wells, a 5.6-mile radius around the injection well will be used. Additionally, the Permittee is required to implement all applicable actions found in Sections K and L of this Permit.

The Texas Administrative Code, 16 TAC § 3.9(3)(B), requires disposal wells to include a review of USGS earthquake records within a circular area with a radius of 9.08 kilometers (5.64 miles) around the proposed well location. The Permittee shall provide the Director with the specific details of any private seismic array and information collected in accordance with those requirements prior to injection.

R. COMMENCING INJECTION

The Permittee may not commence injection until:

1. Results of the formation testing and logging program, as specified in Section J - PRE-INJECTION TESTING of this Permit and in 40 CFR 146.87, are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L - MECHANICAL INTEGRITY of this Permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan highlighted in ATTACHMENT 2: AREA OF REVIEW AND CORRECTIVE ACTION PLAN of this Permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating the Area of Review and Corrective Action, Financial Assurance, Testing and Monitoring, Well Plugging, Post-Injection Site Care and

Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The Permittee's financial instruments are fully effective in accordance with ATTACHMENT 3: FINANCIAL RESPONSIBILITY DEMONSTRATION of this Permit;

6. The Permittee has submitted to and received approval from the Director in an electronic format a notice that all construction is complete and in compliance with 40 CFR 146.86 and the conditions of this Permit;

7. The Director has approved the demonstration of the alarm system and shut-off system under Section K - INJECTION WELL OPERATION of this Permit; and

8. The Director has given written authorization to commence injection.

ATTACHMENTS

ATTACHMENT 1: SUMMARY OF OPERATING REQUIREMENTS

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Injection Well Operating Strategy

Stage	Interval	**Injection Well No. 1 (Labelle Properties LTD #1)**			
		Maximum Allowed BHP (psi)	Injection Volume (MT)	Average Injection Rate (MMta)	Maximum Injection Rate (MMta)
1	Frio	4,620	3.34	1.67	2.5
2	Frio	4,463	3.34	1.67	2.5
3	Frio	4,323	3.34	1.67	2.5
4	Fleming	3,417	2.86	1.43	2.5
5	Fleming	3,154	2.86	1.43	2.5
6	Fleming	2,577	2.52	1.26	2.5
7	Fleming	2,107	1.1	1.1	2.5
Total			19.36		

Injection Rate and Pressure

Table 4-31 provides the proposed operations for the injection wells including injection rate and pressure by well. The maximum injection rates for the injection intervals of each well ranges from 0.73 to 1.67 MMta. The average injection rate range is from 0.73 to

1.67 MMta. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-31. Both the injection rates and pressures are within the operating window of the injection wells.

Table 4-31—Summary of Injection Parameters for Injection Wells No. 01, No. 02, and No. 03

Stage	Stage	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
1	Frio-1	Maximum Injection Zone Rate (MMta)	1.67	1.67	1.67
		Average Injection Zone Rate (MMta)	1.67	1.67	1.67
		Maximum Allowed BHP (psi)	4,620	4,670	4,553
		Maximum Modeled BHP (psi)	3,720	3,828	3,796
2	Frio-2	Maximum Injection Zone Rate (MMta)	1.67	1.67	1.67
		Average Injection Zone Rate (MMta)	1.67	1.67	1.67
		Maximum Allowed BHP (psi)	4,463	4,463	4,368
		Maximum Modeled BHP (psi)	3,543	3,588	3,518
3	Frio-3	Maximum Injection Zone Rate (MMta)	1.67	1.67	1.67
		Average Injection Zone Rate (MMta)	1.67	1.67	1.67
		Maximum Allowed BHP (psi)	4,323	4,320	4,223
		Maximum Modeled BHP (psi)	3,544	3,482	3,473
4	Fleming 3-1	Maximum Injection Zone Rate (MMta)	1.43	0.94	0.94
		Average Injection Zone Rate (MMta)	1.43	0.94	0.94
		Maximum Allowed BHP (psi)	3,417	3,484	3,386
		Maximum Modeled BHP (psi)	2,825	2,705	2,617
5	Fleming 3-2	Maximum Injection Zone Rate (MMta)	1.43	0.94	0.94
		Average Injection Zone Rate (MMta)	1.43	0.94	0.94
		Maximum Allowed BHP (psi)	3,154	3,092	3,108
		Maximum Modeled BHP (psi)	2,627	2,623	2,568

6	Fleming 2	Maximum Injection Zone Rate (MMta)	1.26	1.26	0.73
		Average Injection Zone Rate (MMta)	1.26	1.26	0.73
		Maximum Allowed BHP (psi)	2,577	2,668	2,551
		Maximum Modeled BHP (psi)	2,140	2,152	2,165
7	Fleming 1	Maximum Injection Zone Rate (MMta)	1.10	1.32	0.88
		Average Injection Zone Rate (MMta)	1.10	1.32	0.88
		Maximum Allowed BHP (psi)	2,107	2,113	2,053
		Maximum Modeled BHP (psi)	1,777	1,868	1,811

The proposed continuous monitoring and recording devices will demonstrate internal mechanical integrity [40 CFR 146.88(e)] and that the well is equipped with shutoffs and safety devices that are linked to final operating limits specified in the permit for each injection well. The anticipated bottomhole injection pressures and interval-specific pressure constraints are shown in Tables 4-32 through 4-34. The injection depths are based on the current geologic model and stratigraphic well results. The injection rate schedule presented in this Application is based on defined rate limitations without the modeled projections predicting sufficiently high reservoir pressures that result in maximum BHP constraining predicted well operations.

Table 4-32: Injection Pressures and Pressure Constraints by Injection Stage for Injection Well No. 01

Completion Stage	Completion Years after Startup	Top Depth TVDSS (ft)	CBI [redacted]	Fracture Pressure (psi)	Maximum Allowable BHP (psi)
Upper Frio Sand	0.00	7,440	CBI [redacted]	5,134	4,620
Upper Frio Sand	2.00	7,186	CBI [redacted]	4,985	4,463
Upper Frio Sand	4.00	6,961	CBI [redacted]	4,803	4,323
Fleming Sand 3	6.00	5,584	CBI [redacted]	3,797	3,417
Fleming Sand 3	8.00	5,154	CBI [redacted]	3,505	3,154
Fleming Sand 2	10.00	4,210	CBI [redacted]	2,863	2,577
Fleming Sand 1	12.00	3,495	CBI [redacted]	2,342	2,107
psi = pounds per square inch; TVDSS = True Vertical Depth Subsea					

CO2 Volume

ExxonMobil plans to inject approximately 53 million metric tonnes of CO2 over the life of the Project. It is projected that the CO2 will be injected and will remain in a supercritical state through the life of the Project. The Fleming and Upper Frio sands have relatively high porosity and high permeability. These reservoir properties and the lateral extent of the injection zone are projected to allow the system to store significant volumes of CO_2 with limited reservoir pressure rise and to result in relatively rapid pressure fall-off upon shut-in. The CO_2 volume was determined to meet the requirements of managing the threat of endangerment to USDW.

Annulus Pressure

The annulus pressure will be adjusted to be more than 100 psi above the wellhead injection pressure, with a maximum allowable pressure of 2,750 psi. The minimum annulus pressure is 500 psi, as reported in ATTACHMENT 6: TESTING AND MONITORING PLAN.

Well Stimulation Procedures

In the event it is necessary to achieved desired injectivity, ExxonMobil may stimulate the injection zone for the Rose CCS Project (Appendix D.3). Stimulation may be conducted if injection impairment is observed during the life of the well. Additional details on the stimulation plan can be found in Appendix D.3. Potential causes for injection reduction are:

- Formation damage (e.g., fines migration, scaling, debris in injection stream)
- Geochemical reactions due to fluid / reservoir incompatibility
- Salt precipitation due to in situ brine vaporization
- Reservoir compartmentalization or facies variation
- Shale swelling
- Others

ExxonMobil, will provide advance notice of the proposed stimulation to the UIC Program Director in writing at least 30 days prior to implementation in accordance with 40 CFR 146.91(d)(2). The detailed stimulation plan is provided in Appendix D and incorporates the following:

- Stimulation design to ensure the treatment will not interfere with containment
- Stimulation fluids detail (e.g., volumes, concentrations, additives)
- Stimulation fluid / well material compatibility analysis
- Well Integrity analysis (e.g., casing / tubing stress analysis)
- Stimulation procedure

The stimulation fluids will be an acid, most likely HCl, or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned in the paragraph above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Program Director should a stimulation become necessary:

1. Determine compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop stimulation plan based on the injection impairment cause

3. Provide work procedure and stimulation program to the UIC Program Director in writing at least 30-days prior to the planned date for start of the work (40 CFR 146.91(d)(2)).

4. Prepare wellsite and mobilize equipment

5. Shut-in and isolate the well from the CO2 injection system. Allow the pressures to stabilize

8. Rig up the stimulation equipment.

9. Prepare the well for stimulation.

10. Perform the stimulation treatment as per approved plan.

11. Flush the wellbore with treated water and prepare the well to return to normal operation

12. Rig down and return the well back to injection

CO2 Stream Characteristics

The CO2 stream chemical composition is described in Table 4-10. No solids are expected to be present in the CO2 stream and the composition is >97 mole percent CO2.

In general, unanticipated interactions among the CO2 injectate and the reservoir fluids are not expected that would act to reduce the permeability, porosity, or injectivity of CO2 into the injection intervals over the life of Project. Specific mineralogy and fluid testing were performed on core and fluid samples taken from the stratigraphic well to confirm these conditions prior to issuance of the Class VI permits. This included an assessment of the potential for mineral dissolution or precipitation within the Fleming and Upper Frio injection intervals that could potentially endanger USDWs. As outlined in this section, the current engineering design basis includes corrosion resistant well completion materials selected to provide a high degree of mechanical integrity under future conditions for the formation fluids and CO2 plume. See Section 6.2.5 for a summary of the proposed CO2 compatible cement.

Section 5 – Testing and Monitoring Plan provides a description of the analyses of the CO2 stream for the Project, including tests for potential impurities that may be present and whether such impurities might alter the corrosivity of the injectate downhole. The information provided in Section 5 was based on the expected chemical and physical characteristics of the CO2 stream and will be used to refine the well operating parameters while maintaining compliance with the Class VI permits.

A sample of the CO2 stream will be collected and analyzed for the suite of parameters listed in Table 5-3 prior to commencing injection and throughout injection operations at the proposed frequency. The details of the sampling process and frequency are described in Section 5 for approval by the UIC Program Director.

Operational Reporting Plan

During the operational phase of the Project, ExxonMobil will report, within 24 hours, a confirmed endangerment to USDWs to the UIC Program Director pursuant to the requirement in 40 CFR 146.88(f)(3); 146.91(c); and 146.94(b)(3), including:

- Evidence that the CO_2 plume or pressure front may endanger a USDW or USDWs;
- The non-compliance situation as it relates to a permit condition;
- Apparent malfunction of the injection system;
- Triggering of a shut-off system or a loss of mechanical integrity; or
- A release of CO_2 to the atmosphere or biosphere.

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO_2 to an unauthorized zone in the event that there is a loss of mechanical integrity.

<u>Injection Well Construction and Operation Summary</u>

The geologic setting for this Project is ideally situated for carbon sequestration because of the geologic properties of the injection and confining zones and the compatibility of the reservoir fluids with CO_2. The Project brings together the proven engineering practices of ExxonMobil in the design of the wells with a state-of-the-art monitoring system and a robust reservoir management strategy. The well designs are engineered to address the potential risks associated with the installation and operation of Class VI injection wells with a primary objective of protecting USDW from the threat of endangerment. The engineering design of the casing setting points, materials, and cement meet and exceed the requirements for Class VI injection well and for the conditions that have been projected for the Project. In addition, the operating strategy is designed to manage the pressure effects of CO_2 injection in the injection zones, to use the available pore space to the fullest extent, and to mitigate potential issues through a robust operational and testing and monitoring strategy.

ATTACHMENT 2: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Area of Review and Corrective Action Plan

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting this Underground Injection Control (UIC) Class VI Permit Application (Application) to the United States Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage (CCS) Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a maximum of five million metric tonnes per annum (MMta) of carbon dioxide (CO2) using three injection wells over an injection period of up to 13 years. The predicted total CO2 storage is 53 million metric tonnes. The Area of Review (AoR) and Corrective Action Plan was prepared to meet the requirements of Code of Federal Regulations, Title 40, Section 146.84(b) [40 CFR 146.84(b)] and Texas Administrative Code, Part 1 Title 16 Chapter 5.

No significant risk to underground sources of drinking water (USDW) was identified because the confining zone characteristics are consistent with the requirements of 40 CFR 146.82(a)(3)(iii) for confining the CO2 plume. Two artificial penetrations are located within the refined AoR that require corrective action. The two artificial penetrations, which cross the upper composite confining zone (UCCZ), have been addressed in advance of CO2 injection. One of the artificial penetrations (Bead Farm Co. #1) has been plugged across the UCCZ and subsequently converted to an above-zone monitor for collection of fluid samples above the UCCZ. ExxonMobil is pursuing individual Class VI permits to convert for three injection wells. Given the close proximity of the injection wells for the Project, ExxonMobil plans to obtain approval from the UIC Program Director to delineate the AoR and prepare the Corrective Action Plan to represent the collective effects of the three injection wells within Project AoR. Although the effects were evaluated in the collective, the required maps showing the delineated AoR and the Corrective Action Plan for artificial penetrations are submitted separately for each well so that they may be incorporated into each injection well's Class VI permit.

Objectives

A comprehensive modeling and evaluation effort was undertaken to accomplish the following objectives, consistent with the requirements of 40 CFR 146.84(b):

- Predict the extent of the CO2 plume and pressure front, which form the basis for the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Provide a plan to perform the required corrective action on artificial penetrations in the AoR [40 CFR 146.84(d)] that could threaten USDW;
- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed;
- Help direct emergency response planning by identifying potential vulnerable areas within or near the AoR that could require consideration when implementing an emergency response;
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)];
- Provide a guide for periodic AoR reevaluations to informed site management and monitoring over the lifecycle of the injection Project [40 CFR 146.84(e)]; and
- Retain modeling inputs and data used to support AoR reevaluations for 10 years [40 CFR 146.84(g)].

Facility Information

The following facility information is provided to specify the names and locations of the three injection wells.

Geologic Sequestration Project name:	ExxonMobil Low Carbon Solutions Onshore Storage LLC – Rose Carbon Capture and Storage Project

Injection Well Information:

Well Name and Number	Labelle Properties Ltd #1 (**Rose CCS Project Injection Well No. 01)**
County	Jefferson
Location (RR D, S, A)	Railroad District 3, Section 42, Abstract 874
Latitude / Longitude (NAD83)	29.999678 / -94.285108
American Petroleum Institute	4224532913

Derivation of Input Parameter Values for Geologic Properties

ExxonMobil recognizes that parameter values for the prediction of the AoR are to be based on site-specific data to the extent possible. A stratigraphic well (Bead Farm Co. #1; American Petroleum Institute [API] 4224532908) was completed and core samples were collected from the well to obtain the necessary site geologic characterization data for the CO_2 plume model. Additionally, where appropriate, the parameter values were estimated from standard values published for similar rock types and relationships in the scientific literature. As outlined below, ExxonMobil derived initial estimates of formation intrinsic permeability, porosity, relative permeability, compressibility, fluid viscosity, and fluid density from the available information, with emphasis on the available stratigraphic well data and test results, as appropriate.

The site-specific characteristics that make the Project site ideal for carbon sequestration are described in Section 2.12 of Section 2 – Site Characterization. In summary, the sands of the Fleming and Frio Formations exhibit high porosity and permeability that are ideal for CO_2 storage and are “of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream” [40 CFR 146.83(a)(1)]. Both the UCCZ and Anahuac Shale are thick, continuous sealing intervals across the AoR and are sufficient to “contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone” [40 CFR 146.83(a)(2)].

Porosity and Permeability

Porosity information was obtained from 16 well logs within the geologic model of the area of interest, which includes the AoR and a significant area surrounding the AoR. This information was utilized to generate a three-dimensional geologic model for the Project area. Most of the porosity data were provided based on compressional sonic data. Some bulk density data were also used to inform the estimates of porosity for the formations. Porosity and permeability data were gathered from the stratigraphic well (Bead Farm Co. #1) and incorporated into the geologic model for the Project area.

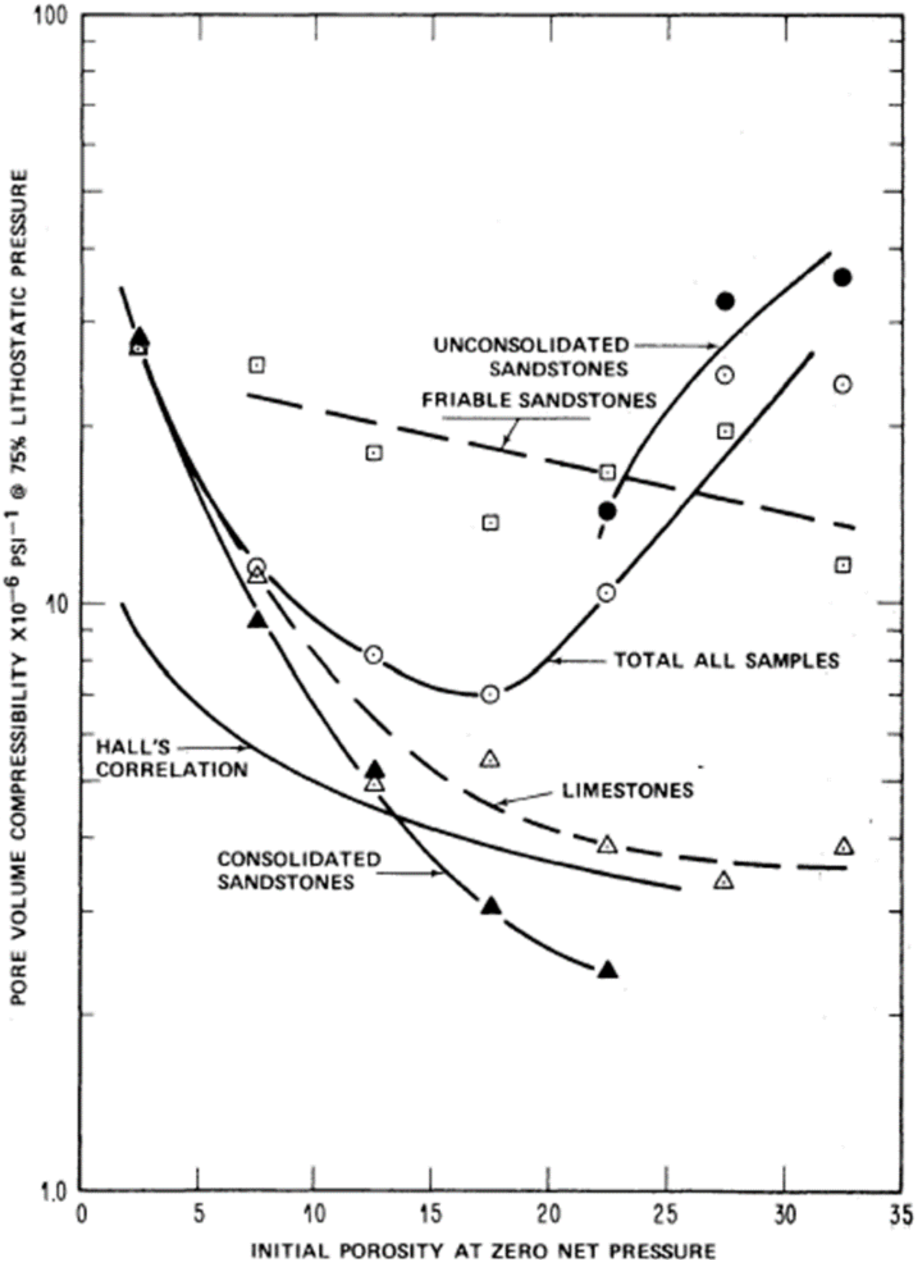
Permeability was modeled based on the results of the total porosity estimate calculations. Separate porosity-permeability transforms were developed for the Fleming and Frio. The nuclear magnetic resonance log was calibrated against core from the stratigraphic well and used to define porosity-permeability relationships across the range of net reservoir facies to address limitations in the core analyses. This relationship was then upscaled using Swanson’s mean to account for differences between core, log, and model scales (Delfiner, 2007).

The results presented below reflect a site-specific set of properties that extend beyond the predicted extent of the CO_2 plume and the AoR boundary. The results of the model continue to demonstrate, as did the initial model effort, how the sequestration of CO_2 is protective of USDWs.

Rock Compressibility

Based on the rock compressibility measurements for the sandstone samples collect at the stratigraphic well, an average value of CBI [redacted] These values are reasonably consistent with the available literature values. Figure 3-1 provides a literature-based relationship between pore volume compressibility and initial porosity. The average rock compressibility values derived from various cored intervals of the stratigraphic well are demonstrated in Figure 3-2. These values are consistent with the literature-based ranges described in Figure 3-1.

Figure 3-1: Pore Volume Compressibility as a Function of Initial Porosity



Source: Newman, 1973

Figure 3-2: Sand Compressibility Unload/Reload Above Initial Reservoir Pressure from Bead Farm Co. #1

[redacted]

<u>Relative Permeability</u>

Relative-permeability curves were generated based on research of analogous depositional environments. Traditional core testing has difficulty accurately measuring the endpoints of the curves, resulting in high irreducible water saturations and low CO2 endpoints (Benson et al., 2013). In drainage CO2-brine relative-permeability experiments, as water saturation decreases, capillary forces become larger [i.e., capillary pressure (Pc)] and increase rapidly in the approach to the irreducible water saturation. During the experiment, the increase in capillary forces limits further reduction in water saturation (i.e., the viscous force is too small relative to the capillary force). This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation. For this reason, it is recommended to fit a Corey-Brooks expression to the experimental data and to extrapolate the curve to a representative value of irreducible water saturation.

[redacted]

Table 3-1: Relative-Permeability Bins and Associated Parameters

[redacted]

[redacted]

The irreducible water saturation was assumed to be in the range of 6 percent (%) to 42% based on published values for various sand qualities in the available Gulf Coast regional data. Fitting the endpoints to the experimental data resulted in brine and CO_2 exponents of 5 and 2, respectively. The geologic model permeability property is based on absolute gas permeability shown on Figure 3-3.

Figure 3-3: Drainage and Imbibition Relative-Permeability Function

[redacted]

The Corey function for gas and water relative permeability is defined as follows, where the Corey exponents are listed in Table 3-1 to be 2 and 5 for gas and water phases, respectively.

(Eq. 1) $$k_{rg} = k_{rg,max} \times \left(\frac{S_g - S_{gc}}{1 - S_{gc} - S_{wirr}}\right)^{n_g}$$

$$k_{rw} = k_{rw,max} \times \left(\frac{1 - S_g - S_{wirr}}{1 - S_{wirr}}\right)^{n_w}$$

$$S_{g,max} = 1 - S_{wirr}$$

The gas hysteresis behavior was incorporated into the displacement curve to account for trapped gas as a CO_2 storage mechanism. The approach represents CO_2 replacing water as gas saturation, and the amount of CO_2 increases until it reaches maximum gas saturation. Afterwards, during the imbibition process, water drives CO_2 out of the pore space and gas saturation decreases until it reaches trapped gas saturation (S_{gt}). This value can be measured through laboratory testing. The initial estimate of S_{gt} was based on available literature and the following correlation (Land, 1971):

(Eq. 2) $$C = \frac{1}{S_{gt}} - \frac{1}{S_{g,max}}$$

For the Project, a value of C = 2.2 was chosen based on published clastic rock measurements (Land, 1971). This results in an initial estimated trap gas saturation value of 0.3.

Capillary Pressure

Initial estimates of capillary pressure were estimated using capillary pressure functions by the Brooks-Corey capillary pressure model:

(Eq. 3) $$P_c = P_{c,th} \times S_{wn}{}^{B}$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$$

where $P_{c,th}$ is threshold (entry) capillary pressure.

A range of 0 < $P_{c,th}$ < 3 psi was assumed to be a reasonable quality clastic rock at reservoir conditions. The values chosen for each S_{wirr} bin are listed in Table 3-1. Exponent B is related to pore size distribution index l and estimated based on Burdine's theory:

(Eq. 4) $$B = \frac{1}{I} = -\frac{nw-3}{2}$$

In a gas-water system, the Brooks-Corey capillary pressure model (Eq. 3) indicates that the capillary pressure curves steepen as they approach the irreducible water saturation point. The five sets of capillary curves are plotted in Figure 3-4.

Figure 3-4: Capillary Pressure Functions

[redacted]

Fluid Pressure

The average formation fluid pressure gradient was derived from [redacted] formation pressure data points acquired from the stratigraphic well. The pressure gradient value is [redacted] represented in Figure 3-5. This original reservoir pressure gradient was based data points collected from [redacted] and was considered representative of sand intervals to be used for injection. The measured site-specific values are consistent with expected values obtained from available literature, which reported an average value of approximately 0.45 psi/ft (Kreitler, 1988).

Figure 3-5: Stratigraphic Well (Bead Farm Co. #1) Pressure Gradient

[redacted]

Temperature

Based on data collected from the stratigraphic well, the temperature gradient is [redacted] Mean surface temperature was assigned as 68 °F, yielding an original temperature of [redacted] in the reservoir model at a reference depth of [redacted] The original temperature was assigned to be consistent with this temperature and the temperature gradient throughout the model domain. The temperature gradient is represented in Figure 3-6.

Figure 3-6: Stratigraphic Well (Bead Farm Co. #1) Temperature Gradient

[redacted]

Formation Compressibility
Total formation compressibility includes rock compressibility (Section 3.3.2) and fluid compressibility (Section 3.4.3). Both are accounted for during simulation of CO2 injection.

Initial Saturation
A review of the available literature (Kreitler, 1988) indicates the target Fleming and Frio injection intervals in this area of the Gulf Coast are expected to be saline aquifers of 100% water saturation. [redacted]

Derivation of Input Parameter Values for Fluid Properties

Fluid Composition

Fluid samples were collected from the stratigraphic well and analyzed for fluid composition. The results of laboratory analyses for total salinity are summarized in Table 3-2. The simulation model utilized average salinity of [redacted] at reference depth of [redacted] and salinity of [redacted] at reference depth of [redacted] A detailed fluid analysis is presented in Section 2.9 of Section 2 – Site Characterization.

Table 3-2: Bead Farm No.1 Fluid Sampling Results

Formation	Depth (ft)	Salinity (ppm)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

Fluid Density and Viscosity

Brine and CO_2 properties (including density, viscosity, and compressibility) are functions of pressure, temperature, and salinity. Industry standard methods can be employed to determine the pure phase properties and their interaction.

For this study, a specific CO_2 sequestration compositional modeling method was used that was developed by Schlumberger for the Eclipse™ numerical reservoir simulator (version 2020.4).

This specific model, called CO2STORE, can accurately evaluate fluid density and viscosity based on following method in Eclipse™:

- The gas density is obtained by an accurately tuned cubic equation of state;
- The brine density is first approximated by the pure water density and then corrected for salt and CO_2 effects by Ezrokhi's method (Zakirov et al., 1996); and
- The CO_2 gas viscosity is calculated using methods provided by Vesovic et al. (1990) and Fenghour et al. (1998).

The dissolution of CO_2 into brine and vice versa resulted in saturated CO_2 and brine solutions that have slightly altered density and viscosity. A sample table for pure phase and saturated phase CO_2 and brine viscosity and density are illustrated below in Table 3-3. The site-specific data were used along with the correlations and functions available in the Eclipse™ model to generate values of density and viscosity at original conditions and the projected conditions that are predicted to be generated in-situ during the course of the simulations.

Table 3-3: Pure Phase and Saturated Phase CO_2 and Brine Viscosity and Density

Depth (ft)	Pressure (psi)	Temperature (°F)	Pure Phase Properties				Saturated Phase Properties			
			CO_2		Brine		CO_2		Brine	
			density (g/cm3)	Viscosity (cp)	Density (g/cm3)	Viscosity (cp)	Density (g/cm3)	Viscosity (cp)	Density (g/cm3)	Viscosity (cp)
3,400	1,530	126.7	0.428	0.033	1.040	0.604	0.438	0.034	1.046	0.601
4,000	1,800	136.4	0.498	0.038	1.038	0.558	0.506	0.039	1.044	0.555
5,000	2,250	152.5	0.547	0.043	1.035	0.493	0.555	0.044	1.041	0.491
6,000	2,700	168.6	0.574	0.045	1.031	0.441	0.581	0.046	1.037	0.439

7,000	3,150	184.7	0.591	0.047	1.027	0.399	0.598	0.048	1.033	0.397
8,000	3,600	200.8	0.604	0.049	1.023	0.364	0.611	0.050	1.028	0.362
cp = centipoise; g/cm^3 = grams per cubic centimeter										

Figures 3-7(a) and 3-7(b) illustrate density variation for CO2 and brine vs. depth. CO2 and brine density vary with pressure, temperature and to a lesser extent saturation of the opposite phase (CO2 in brine or brine in CO2). CO2 density increases with pressure at deeper intervals; this density increase is partially offset by higher temperature, but the dominant control on CO2 density in this depth range is pressure. Saturation of CO2 with brine slightly increases CO2 density at all depths as shown in Figure 3-7(a). Brine density exhibits the opposite trend. At deeper intervals, brine becomes less dense with higher temperature, which is partially offset by pressure increase. Similarly, brine density increases slightly when saturated with CO2, as compared to pure phase brine. Figures 3-7(a) and (b) are illustrative; CO2 and brine density are calculated in the simulation based on local conditions (temperature, pressure, and saturation) using built-in correlations in Eclipse.

Figure 3-7(a): Pure Phase and Saturated Phase CO2 Density vs Depth

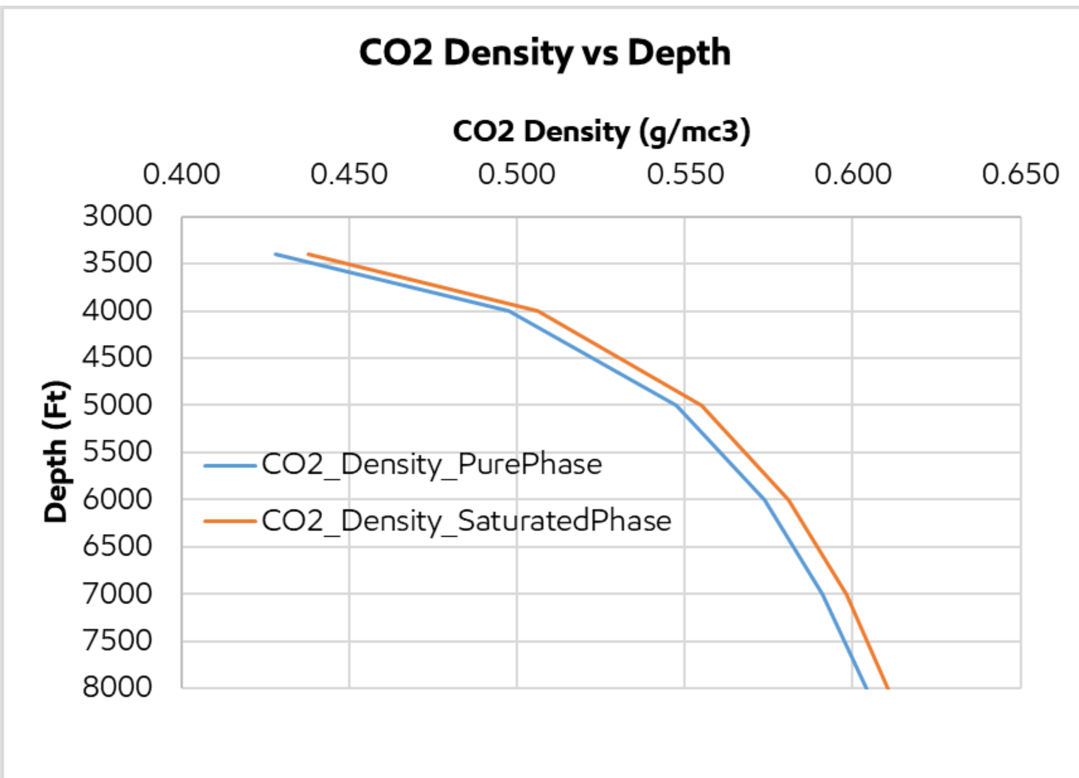
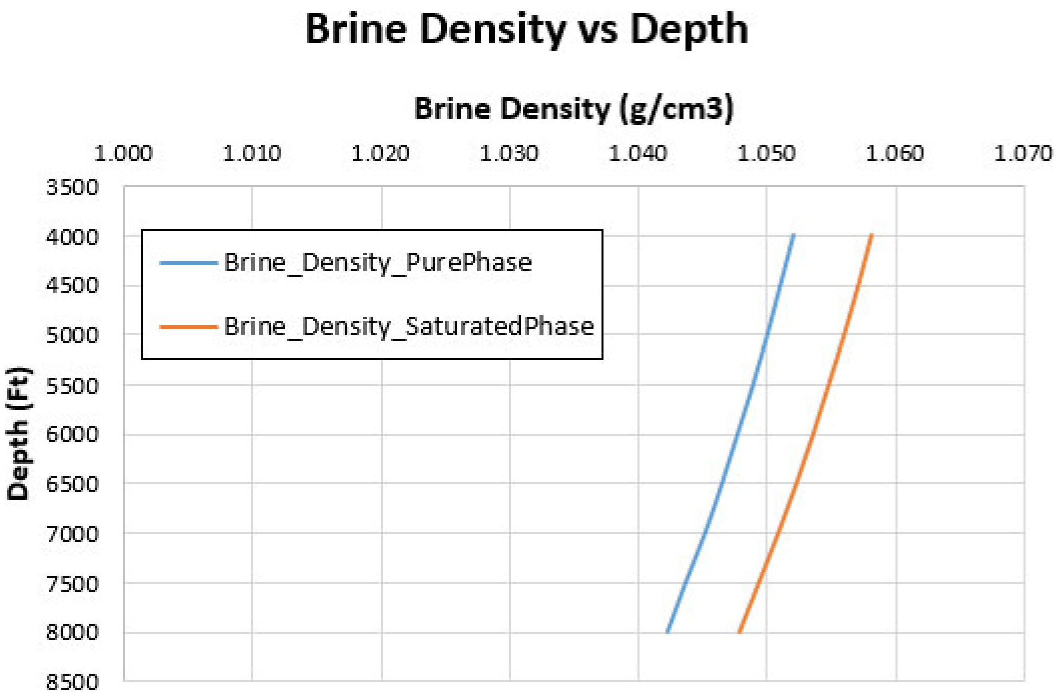


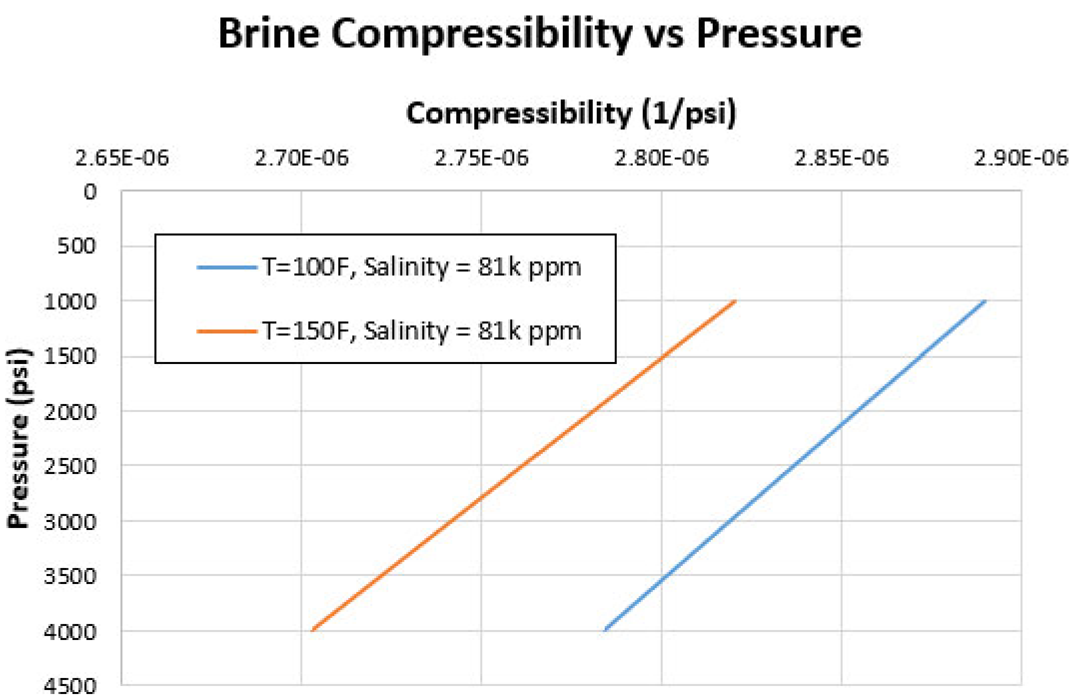
Figure 3-7(b): Pure Phase and Saturated Phase Brine Density vs Depth for Salinity = 81,000 ppm Case



<u>Fluid Compressibility</u>

Brine is often considered as an incompressible fluid but has a small compressibility in the range of 2.5 to 3.5 µsips depending on pressure and temperature. Brine compressibility is handled by the simulator based on original conditions extrapolated from the stratigraphic well measurements and predicted conditions that develop during simulation runs. The range of pressure and compressibility is illustrated on Figure 3-8. While the injected CO2 for this Project will remain in dense phase from wellhead to the reservoir, its density can vary with pressure and temperature. Compressibility of CO2 is typically higher compared to formation and brine, as illustrated in an earlier study that showed a range of 50 to 80 µsips (Law and Bachu, 1996). In this simulation study, CO2 compressibility is automatically handled by the simulator based on an equation-of-state calculation.

Figure 3-8: Brine compressibility at Different Pressure and Temperature



<u>Derivation of Input Parameter Values for Chemical Properties</u>

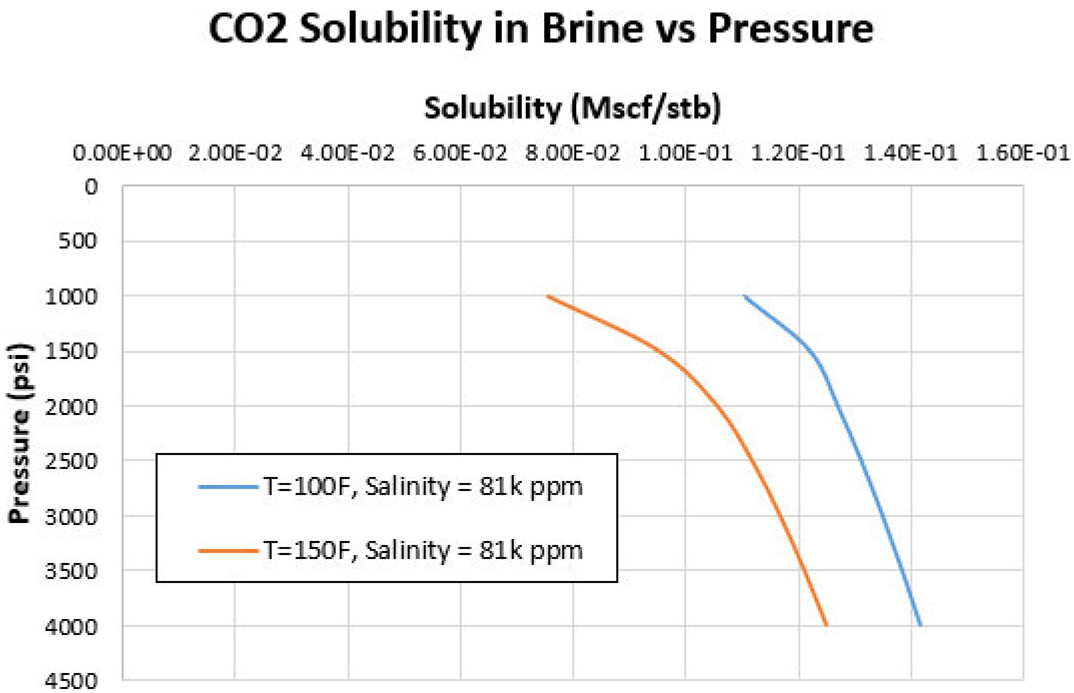
<u>Aqueous Solubility</u>

CO2 can dissolve in water and dissolved CO2 is considered permanently sequestrated in the saline aquifer. Therefore, dissolution is an important sequestration mechanism.

The compositional model leverages the CO2STORE option in the Eclipse™ simulator, which models mutual solubilities of CO2 and water based on matching experimental data for typical CO2 storage conditions: typically, 54 to 480 °F and up to 8,700 psi, which includes the pressure and temperature range for the AoR. The mutual solubilities are calculated following the procedure given by Spycher and Pruess (2009), based on fugacity equilibration between water and a CO2 phase. Water fugacity is obtained by Henry's law, while CO2 fugacity is calculated using a modified Redlich-Kwong equation of state.

A sample-calculated CO2 solubility is presented on Figure 3-9. The CO2 solubility is dependent on temperature, pressure, and salinity. As shown, CO2 has a range of solubility between 0.05 to 0.15 thousand standard cubic feet per stock tank barrel.

Figure 3-9: CO_2 Solubility in Brine at Different Temperature



<u>Solubility in Carbon Dioxide</u>

The solubility of brine in CO_2 at reservoir conditions is limited, which is explained in Section 3.4.2. This behavior is captured by the CO2STORE option and is incorporated into simulation forecasts. However, it has negligible impact on storage potential.

<u>Model Design and Input Parameters</u>

The model design is based on the use of computer simulation tools with a proven record of modeling multiphase flow. The input parameter values include a combination of uniform values throughout the domain and values that vary in space and time. The derivation of input parameter values for the hydrogeologic system were based on several data sources and relationships that were outlined above.

In addition to the set of model parameters described below, parameter sensitivity analyses were performed during the pre-operational phase and their impacts were assessed. The most impactful uncertainty parameters for CO_2 plume include reservoir permeability architecture and reservoir temperature. The most impactful parameters for pressure AoR include reservoir permeability architecture, aquifer strength, vertical to horizontal permeability (k_v/k_h) ratio, fault transmissibility, and rock compressibility. Other parameters assessed include relative permeability function parameters (e.g., Corey coefficients, trapped gas saturation, capillary entry pressure) and skin, which show less impact. The following parameters were calibrated during the Rose project appraisal program: reservoir temperature, rock permeability, compressibility, and relative permeability parameters. Based on these analyses and data acquisition, the following basis represents a best estimate for expected performance. Monitoring data collected during the life of the project will be used to calibrate the model and improve forward predictions.

<u>Model Background</u>

Schlumberger's Petrel™ Software was chosen to create a detailed geologic model for the Project. This software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of the underground reservoir. The Petrel™-developed geologic model incorporates the geologic layers of the site described in the Section 2 – Site Characterization, including three targeted injection zones within the Fleming Formation (referred to as Fleming Sand 1, Fleming Sand 2, and Fleming Sand 3) and one targeted injection interval within the Frio Formation (referred to as the Upper Frio, which is a combination of Frio Sand 1 and Frio Sand 2). Using Petrel™, the properties of the injection intervals were modeled in three dimensions, a detailed description of which is given in Section 2.

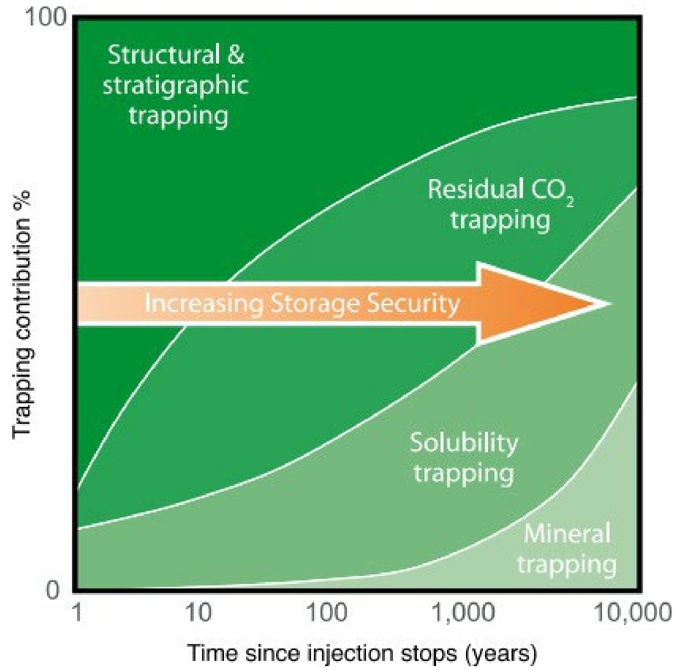
The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse™ numerical reservoir simulator. Eclipse™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to evaluate compositional, chemical, and geochemical processes to produce a reliable simulation for CCS. The software has modules and options specifically intended to allow the study of CCS injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

In a CO2 storage project, four primary trapping mechanisms sequester the supercritical CO_2, schematically represented in Figure 3-10(a):

1. Structural and stratigraphic trapping
2. Residual trapping
3. Solubility trapping
4. Mineral trapping

The mineral trapping mechanism is not explicitly included in the current CCS modeling process. The results of reaction-path geochemical modeling described in Section 2.9 – Assessment of Injection Interval and Confining Zone Geochemical Reactions support that the influence of mineral precipitation/dissolution and geochemical reactions on reservoir parameters such as porosity and permeability are predicted to be negligible over the lifetime of the project. Based on these modeling results, it was not deemed necessary to conduct reactive transport modeling that considers both hydrodynamic flow and geochemical reactions. Instead, the only chemical parameters considered in the AoR model are the solubility of CO2 in the brine and the total dissolved solids of the brine, as both parameters have a larger influence on delineating the extent of the CO2 and pressure plumes. Adding geochemical reactions to the model is not expected to influence the results of the model.

Figure 3-10(a): CO_2 Storage Mechanisms



Source: Metz et al., 2005

Figure 3-10(b) shows the breakdown of the trapping mechanisms for this project. Once injection stops (Year 13), the mobile CO2 quickly decreases as CO2 migrates through pore space and is trapped. Over the life of the Rose Project, residual trapping is the most dominant trapping mechanism. Approximately 59% of the injected fluid is safely sequestered by residual trapping within the pore space. The solubility of CO2 into the connate brine will safely store approximately 35% of the CO2. The remaining 6% of the injectate will be structurally and hydrodynamically trapped.

Figure 3-10(b): Modeled Trapping Mechanisms

CBI

[redacted]

[redacted]

System Orientation and Simulation Controls for Model

[redacted] Figure 3-11 presents the orientation and approximate dimensions of the geologic model domain, which is greater than the simulation model grid. The domain extends significantly beyond the predicted plume boundaries to reduce the potential for the model domain boundaries to significantly influence the CO2 plume extent or pressure front migration. This grid was used consistently for the prediction of the AoR. Local grid refinement around wellbore region is also tested, which leads to substantially similar CO2 plume area and critical pressure AoR within 2 to 3% of difference.

A geologic model was used as an input to help build the dynamic plume and pressure prediction model. The initial input parameter values in Table 3-4 were used to initialize the model. The estimated average total porosity and horizontal permeability of the net reservoirs within the Fleming and Frio injection intervals are presented in Table 2-21. [redacted] Vertical permeability is typically lower than horizontal permeability due to the alignment of grains and bedding planes formed at time of deposition. The amount by which vertical permeability is lower can vary by stratigraphic setting and environment of deposition. For high-quality sand intervals, vertical permeability can sometimes approach the same magnitude of horizontal permeability; for lower quality sand intervals with an increased amount of silt and shale facies in the rock, the vertical permeability can be significantly lower than horizontal permeability. In the simulation model, vertical to horizontal permeability ratio k_v/k_h is assigned based on sand quality using three permeability bins, defined in Table 3-4. The k_v/k_h ratio was assigned based on concept models of the environment of deposition supported by core analyses. High quality sand cells with [redacted] generally occur in fluvial channels or delta lobes represented by blocky coarse sand (channel axis, proximal delta); cells with K_h in the range of [redacted] contain sand with thin interbedded silt and shale (crevasse splay, medial delta); cells with K_h in the range of [redacted] contain interbedded sand with higher content of silt and shale facies (flood plain, distal delta).

The initial pore pressure and fracture pressure gradients were calculated to be [redacted] and [redacted], respectively. The estimated temperature gradient is [redacted], which was calculated from measurements made at the stratigraphic well. Salinity was estimated to range from [redacted] based on measurements from the stratigraphic well.

Figure 3-11: Extent of Simulation Boundary, AoR, and Geologic Features in the Model Domain

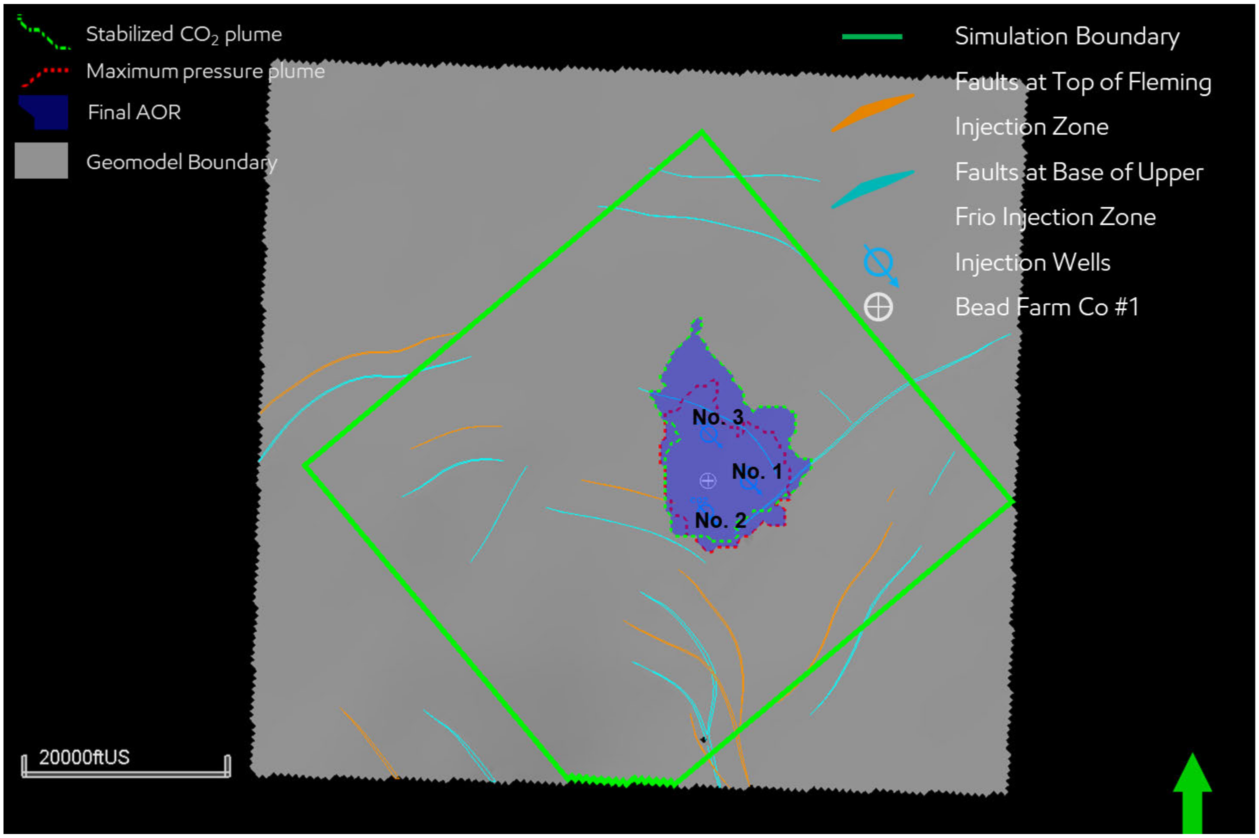


Table 3-4: Summary of Input Parameter Values for Model

Input Parameters	Value
CBI [redacted]	[redacted]

Fluid Injection Rates

The injection wells were simulated using the wellbore design schematics and target rate schedule along with the input parameters provided in Table 3-5. The model utilized seven injection stages. Results of the core sample testing from the stratigraphic wells informed the levels of horizontal and vertical permeability. Fluid injection rates are described in Table 3-5 and the total storage volume was estimated at 46 to 53 million metric tonnes.

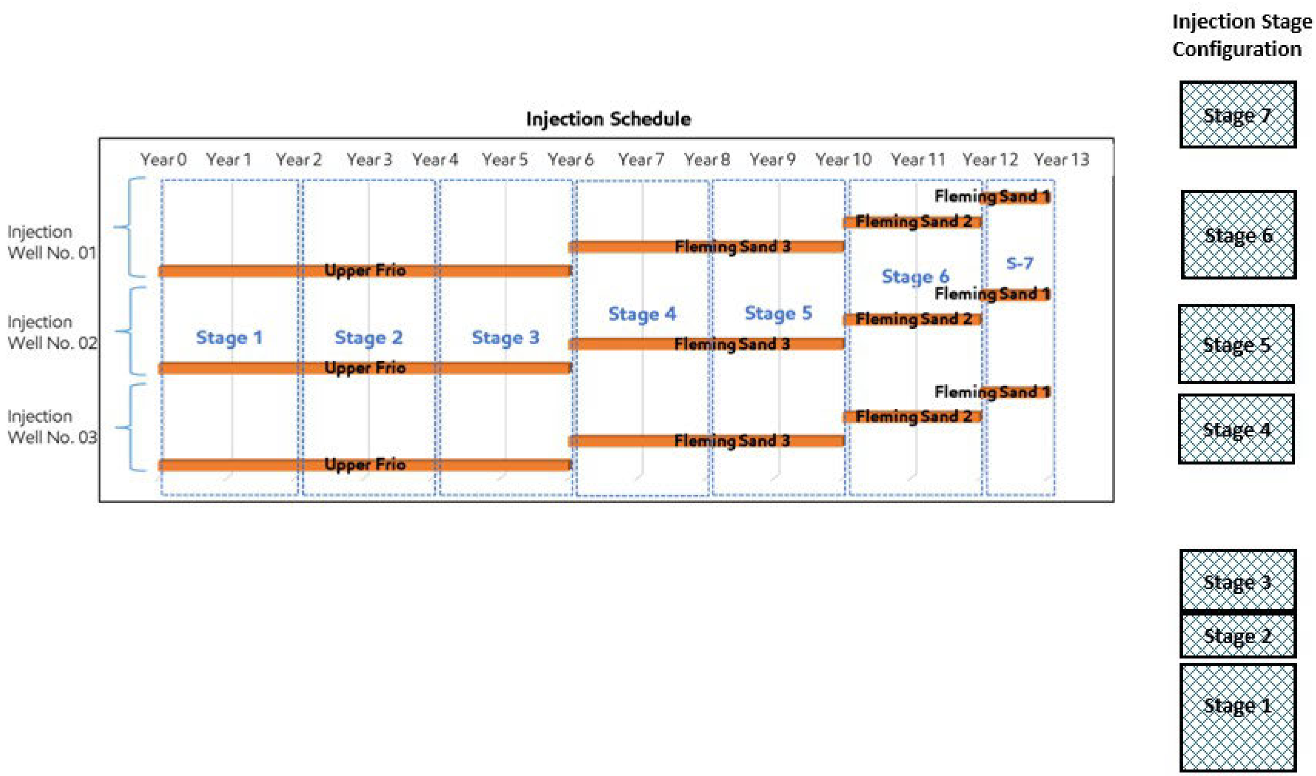
Three primary constraints were imposed to limit plume movement: (1) the maximum injection rate is 1.67 MMta; (2) a maximum bottomhole pressure (BHP) gradient of CBI [redacted] and (3) an injection period of 13 years for all three injection wells. A skin factor of 10 was applied to the wellbore to simulate potential formation damage that may occur over time. This assumption was considered when calculating the wellhead pressure. Injection Wells No. 1, 2, and 3 were simulated at a maximum injection rate of 1.67 MMta. Pressure was not a limiting factor defining the model AoR boundary projections.

Table 3-5: Summary of Input Parameter Values for Injection Wells

Input Parameter Value	Rose CCS Project Injection Wells		
	No. 1	No. 2	No. 3
Max Injection Rate (MMta)	1.67	1.67	1.67
CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
Injection Duration (years)	13	13	13
Roughness Factor	0.0021	0.0021	0.0021
Compressor Outlet Temperature (°F)	80	80	80

The injection wells are divided into multiple completion intervals to optimize the usage of available pore space. Each completion stage represents a portion of the reservoir that will be injected into at a given time. Figure 3-12 shows the planned completion strategy for each injection well.

Figure 3-12: Summary of Injection Intervals and Durations for Each Injection Well



CBI

[redacted]

A total of seven injection stages within the four formation intervals are planned for each well. Perforation depths and injection durations are summarized in Tables 3-6 through 3-8. The perforation depths are based on the current geologic model and will be adjusted based on injection well results.

Table 3-6: Summary of Completion Stages and Intervals for Rose CCS Project Injection Well No. 1

Stage	Interval	Estimated Completion Date (years post startup)	Top Depth TVDSS (ft)	Bottom Depth TVDSS (ft)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)
1	Upper Frio Sand	0.00	7,382	8,025	643	353	2.00
2	Upper Frio Sand	2.00	7,163	7,348	185	185	2.00
3	Upper Frio Sand	4.00	6,938	7,122	185	164	2.00
4	Fleming Sand 3	6.00	5,561	5,922	361	120	2.00
5	Fleming Sand 3	8.00	5,131	5,492	361	223	2.00
6	Fleming Sand 2	10.00	4,187	4,766	579	186	2.00
7	Fleming Sand 1	12.00	3,472	3,932	460	293	1.00
TVDSS = true vertical depth subsea							

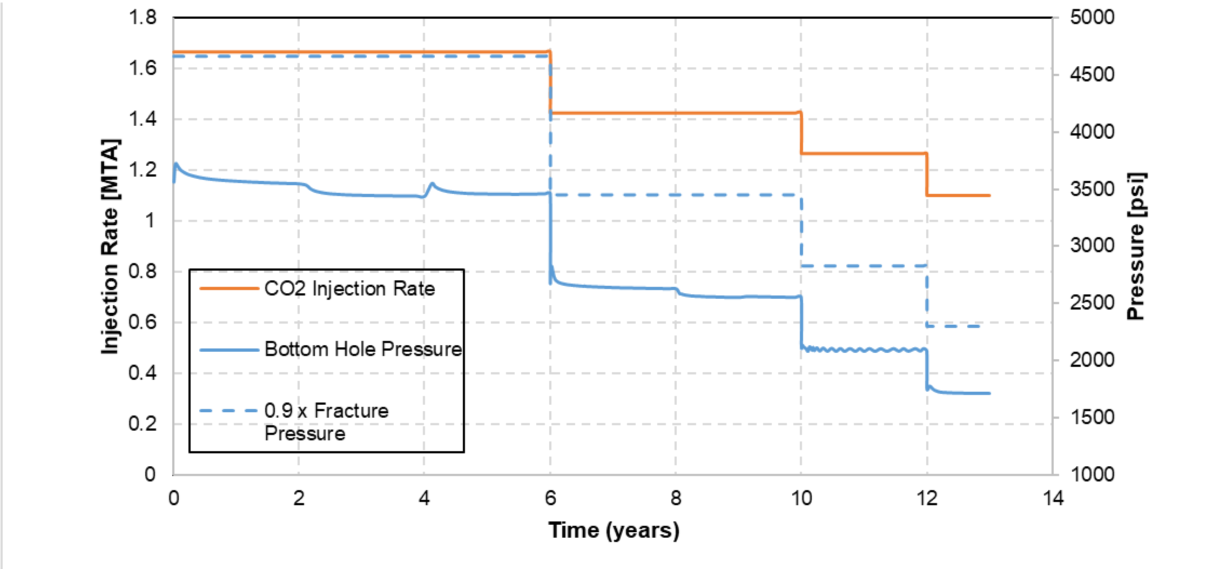
At each new completion, the modeled pressure constraint was updated in the model based on the upper perforation depth. Target injection rates were updated accordingly to meet the limitation that the BHP remained below the calculated fracture gradient. Tables 3-9 through 3-11 summarize injection rate and pressure parameters corresponding to all completions in each well.

Table 3-9: Modeled Injection Rates and Pressures for Rose CCS Project Injection Well No. 01

Stage	Year	Max. Rate (MMta)	Avg. Rate (MMta)	Max. BHP (psi)	Avg. BHP (psi)
1	0	1.67	1.67	3,720	3,600
2	2	1.67	1.67	3,543	3,462
3	4	1.67	1.67	3,544	3,465
4	6	1.43	1.43	2,825	2,667
5	8	1.43	1.43	2,627	2,563
6	10	1.26	1.26	2,140	2,100
7	12	1.1	1.1	1,777	1,731

Continuous injection rates, injection pressures, and associated pressure constraints for each well are illustrated on Figures 3-13 through 3-15.

Figure 3-13: Injection Rates and Pressures – Rose CCS Project Injection Well No. 01



<u>Fracture Pressure and Fracture Gradient</u>

As discussed in Section 2.6 of Section 2 – Site Characterization, a log-based approach was utilized to evaluate undisturbed stress state at the field. The approach incorporated density and dipole sonic logs collected at Bead Farm Co. #1 well and was calibrated with formation integrity data from nearby offset wells. The fracture gradients shown in Table 3-12 have been calculated for the proposed injection zones based on site-specific data.

Table 3-12: Calculated Fracture Gradients for the Proposed Injection Zones

CBI [redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Using the estimated formation tops presented in Table 2-4 in Section 2 – Site Characterization, the estimated maximum bottomhole injection pressures for the top of the Fleming Sand 1 Injection Interval and the top of the Frio Sand 1 Injection Interval are shown in Table 3-13. The safety factor applied is 90% of estimated fracture pressure. Note that these values may be revised based on site data to be collected from injection wells and well completion strategy.

Table 3-13: Maximum Modeled Bottomhole Injection Pressures

Stage	Injection Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
1	Upper Frio Sand (1)	Top Depth (BGL)	7,440	7,520	7,331
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	4,620	4,670	4,553
		Maximum Modeled BHP (psi)	3,720	3,828	3,796
2	Upper Frio Sand (2)	Top Depth (BGL)	7,186	7,186	7,034
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	4,463	4,463	4,368
		Maximum Modeled BHP (psi)	3,543	3,588	3,518
3	Upper Frio Sand (3)	Top Depth (BGL)	6,961	6,956	6,801
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	4,322	4,320	4,223
		Maximum Modeled BHP (psi)	3,544	3,482	3,473
4	Fleming Sand 3 (1)	Top Depth (BGL)	5,584	5,693	5,532
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	3,417	3,484	3,386
		Maximum Modeled BHP (psi)	2,825	2,705	2,617
5	Fleming Sand 3 (2)	Top Depth (BGL)	5,154	5,053	5,078
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	3,154	3,092	3,108
		Maximum Modeled BHP (psi)	2,627	2,623	2,568
6	Fleming Sand 2	Top Depth (BGL)	4,210	4,360	4,169
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	2,577	2,668	2,551

Stage	Injection Interval	Parameter	Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
		Maximum Modeled BHP (psi)	2,140	2,152	2,165
7	Fleming Sand 1	Top Depth (BGL)	3,495	3,504	3,405
		CBI [redacted]	CBI [redacted]	CBI [redacted]	CBI [redacted]
		Maximum Allowed BHP (psi)	2,107	2,113	2,053
		Maximum Modeled BHP (psi)	1,777	1,868	1,811

Boundary Conditions

ExxonMobil selected the boundary condition for the model domain that describes the fluid flow rates and/or pressures at the edges of the model domain and at the location of injection wells. The Fleming and Frio injection intervals are characterized as highly connected throughout the region. Thus, an infinite-acting reservoir boundary condition was selected for the four edges of the rectangular model domain to simulate the pressure response from CO_2 injection. In the model, "volume modifiers" were used along the edges of the model domain to change the gross volume of a grid cell by adding a "multiplier" to the original volume. [redacted]

The "volume modifiers" provide additional pore space for pressure dissipation at the boundary, which reduces the pressure build-up at the edge of the model domain. This effectively simulates the Fleming and Frio injection interval characteristics as being highly connected throughout the region. Care was taken to extend the model boundaries sufficiently far from the injection wells so that the estimates of CO_2 plume and pressure front migration were not influenced by the boundary. Additionally, the upper and lower confining zones were assigned as impermeable layers, based on the site characterization. Any nearby faults were assumed to be transmissive only where sand-to-sand contact was predicted in the Petrel™ output. The approach reduced the potential for the model to predict no CO_2 migration, when a potential for migration was apparent at a fault location.

AoR Delineation Based on Model Results

Extent of CO_2 Plume

The areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of plume extent over a distance of multiple miles. The operational and geologic input parameters were used in the Eclipse™ model to generate projections of plume and pressure migration versus time. Each well was initially completed and then recompleted into incrementally shallower portions of the injection intervals per the schedule presented on Figure 3-12.

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI [redacted]

Figure 3-17: Modeled Areal Plume Size, Growth Rate, and Stabilization

CBI [redacted]

Delineation of the Critical-Pressure Front

In accordance with 40 CFR 146.84, the AoR was delineated by the critical-pressure front created by the injection of CO_2 into the injection intervals. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical-pressure front defined by this pressure contour.

Critical-Pressure Calculations

The methodology for defining the critical pressure was sourced from Nicot (Nicot, 2009), which is referenced in the EPA guidance for calculations based on displacing fluid initially present in a borehole. Nicot assumed that the injection reservoir is in hydrostatic equilibrium, neither under- nor over-pressured, and that a direct path between the injection zone and lowermost USDW exists. An example hypothetical vertical pathway includes an insufficiently plugged and abandoned wellbore.

[redacted] The critical pressure was calculated for each completion phase of each injection well, with the top of the effective injection interval perforations ranging from depths of 3,382 ft to 7,497 ft TVDSS. Based on the site- specific fluid samples from the stratigraphic well, the total dissolved solids (TDS) of the brine was observed to range from [redacted] Applying the minimum measured salinity [redacted] results in a [redacted] psi/ft reservoir pressure gradient if the reservoir was originally in hydrostatic equilibrium with a column of this brine from the depth of the reservoir to surface. The fluid within the USDW was assumed to be fresh water with a fluid pressure gradient of [redacted] Inputs for an example critical pressure calculation (Rose CCS Project Injection Well No. 01; Fleming Sand 1) are provided in Table 3- 14.

Table 3-14: Input Parameter Values for Critical-Pressure Calculation at Rose CCS Project Injection Well No. 01, Fleming Sand 1

Input Parameter	Symbol	Value
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The coefficient (λ) is first calculated in Equation 5 using the final, post-equilibrium pressure gradients and depths for the base of the USDW and top of injection zone:

(Eq. 5) $$\lambda = \frac{G_{if} - G_{uf}}{D_i - D_u}$$

[redacted]

The coefficient (ξ) is then calculated in Equation 6 using the initial gradients and depths for the base of the USDW and top of injection zone:

(Eq. 6) $$\xi = \frac{G_{ii} - G_{ui}}{D_i - D_u}$$

[redacted]

Finally, critical-pressure rise (ΔP_c) is calculated using Equation 7. The inputs include the coefficients (λ, ξ) calculated in Equations 5 and 6 and the depths for the base of USDW (D_u) and top of injection interval (D_i):

$$\text{(Eq. 7)} \qquad \Delta P_c = (D_i - D_u)\left[\frac{\lambda-\xi}{2}(D_i - D_u) + G_{uf} - G_{ui}\right]$$

CBI [redacted]

[redacted]

The resulting critical-pressure rise for the uppermost stage of Rose CCS Project Injection Well No. 01 is positive, indicating that the reservoir pressure may be safely increased by approximately 41.2 psi, without risk of endangerment to the lowermost USDW. The calculated critical-pressure rise for each completion stage of each injection well is included in Table 3-15.

Table 3-15: Calculated Critical-Pressure Rise for Rose CCS Project Injection Intervals

Injection Stage	Interval	Salinity	Critical-Pressure Rise (psi)		
			Injection Well No. 01	Injection Well No. 02	Injection Well No. 03
1	Upper Frio Sand	CBI [redacted]	161.48	163.61	158.58
2	Upper Frio Sand	CBI [redacted]	154.71	154.71	150.67
3	Upper Frio Sand	CBI [redacted]	148.72	148.59	144.46
4	Fleming Sand 3	CBI [redacted]	119.83	122.94	118.35
5	Fleming Sand 3	CBI [redacted]	107.55	104.66	105.38
6	Fleming Sand 2	CBI [redacted]	69.17	72.86	68.15
7	Fleming Sand 1	CBI [redacted]	41.2	41.38	39.42

AoR Delineation

The maximum areal extents of both the CO_2 plume and the critical-pressure front were used to delineate the AoR at any time interval or depth. The larger extent of either CO_2 saturation or critical-pressure rise was used to define the AoR boundary. Figure 3-16 presents the maximum extent of the stabilized CO_2 plume, approximately 26 years into the post-injection site care phase of the Project [redacted] The critical-pressure front, illustrated in Figure 3-18, represents the maximum areal cone of influence and combines results from the seven completion intervals for each of the three injection wells. Figures 3-18 (a)-(d) represent critical pressure fronts assessed at years 1, 5, 10, and 13, respectively. Superimposing the maximum CO_2 plume and critical-pressure boundaries, Figure 3-19 provides the AoR boundary for the Project.

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

CBI

[redacted]

Stages of Model Development

The stages of development for the CO_2 plume and pressure-front model started with pre-operational phase data and industry standards to predict the AoR boundary. The geomodel and reservoir model rely on these data and on industry standard correlations for the assignments of properties based on site-specific conditions. Physical rock property distributions assigned to the model based on geostatistics have been analyzed and are consistent with results from the stratigraphic and development wells and all other available data.
The following objectives were achieved for the pre-operational phase of the model:

1. Verify that the AoR was based on relevant existing and new information and identify where this information supports assumptions used in the model;
2. Align the conceptual/geologic model and model inputs with existing data, including pre-operational testing results at the stratigraphic and development wells;
3. Assess how the AoR model reasonably and accurately represents the geologic and operational systems, including sensitivity analyses, and yields information necessary to delineate the AoR; and
4. Confirm that conservative and reasonable methods were used to delineate the AoR and protection of USDW.

Looking forward to the operational phase of the project, updates will be made to the model for calibration purposes. The model calibration procedures will likely focus on the parameters that have been identified during the pre-operational modeling effort as the most sensitive parameters during sensitivity analyses. The calibration process is intended to be an iterative process, with updates to the geomodel and input parameters, to achieve an acceptable agreement between model predictions and the collected testing and monitoring data.

Corrective Action Plan and Schedule

Consistent with 40 CFR 146.84, the primary objective of this Corrective Action Plan is to identify the potential risk for loss of CO_2 or brine containment through artificial penetrations of the UCCZ and to specify corrective actions that would be taken to restore the integrity of the UCCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AoR. Public and private databases were searched, historical aerial photographs were reviewed, an aeromagnetic survey was conducted across the AoR, and field reconnaissance with ground penetrating radar was conducted at certain locations to reduce uncertainty. When the results of these multiple lines of evidence were compiled, a total of five stratigraphic, legacy oil and gas (legacy wells), and water wells were identified within the AoR as shown on Figure 3-19.
Two artificial penetrations were found to penetrate the UCCZ based on an analysis of the available data. These two artificial penetrations warrant corrective action planning and scheduling based on conservative assumptions regarding the potential for impact by injection and assumptions with respect to well and plug characteristics. Following the requirements outlined in 40 CFR 146.84(c)(2), 146.84(c)(3), and 146.84(d), each artificial penetration within the AoR that may penetrate the UCCZ was evaluated for the quality of casing and cementing in the case of existing wells or for the quality of plugging and abandonment (P&A) in the case of

abandoned wells. The planned corrective actions and schedule outlined in this section are presented for each artificial penetration that could hypothetically serve as a conduit for fluid movement.
This section provides a rigorous corrective action process for each well that begins with additional well assessment activity and ends with establishing incremental barriers to remedy the potential for CO2 or brine crossflow between the injection zones and USDW. The USDW depth range is 1,415 to 1,489 ft KB. For conservative purposes, the USDW depth of 1,489 ft KB was used for setting the USDW cement plugs.

Data Acquisition and Evaluation of Artificial Penetration Information

In accordance with 40 CFR 146.82(a)(4) and 40 CFR 146.84(c)(2), a search was conducted to identify and assess the occurrence of artificial penetrations within and immediately beyond the AoR. Artificial penetrations included oil and gas wells; Class I, II, III, IV, and V UIC wells; water wells; mines; quarries; and potential subsurface cleanup sites. The following data sources were reviewed to identify potential artificial penetrations within the AoR:

- The Railroad Commission of Texas (RRC) GIS Database;
- The Texas Water Development Board;
- Texas Commission on Environmental Quality UIC Central File Room database;
- Brackish Resources Aquifer Characterization System;
- Database for underground mines and quarries (U.S. Geological Survey Mine Related Features and U.S. Geological Survey Mineral Resources);
- State- or EPA-approved subsurface cleanup sites; and
- Third-party Oil and Gas Record Databases including Enverus Drilling Info, IHS Energy Portal, Tobin Data, EMSDB, and HART.

No subsurface cleanup sites, mines, or quarries were identified within the AoR. Based on the well locations identified in the above databases, additional review was conducted utilizing historical records to assess their veracity of each implied well presence, geospatial location, and historical completion, along with plugging, casing, and cementing procedures for each artificial penetration. Duplicative well identifications were merged if appropriate based on the records. The following are additional analyses that were conducted for artificial penetrations:

- Historical aerial photograph reviews for the identified artificial penetration locations;
- A physical record request was made to the RRC, and the available documents were reviewed;
- An aeromagnetic survey of the AoR was completed in August 2023; and
- In-person reconnaissance surveys and use of ground penetrating radar were conducted on November 8, 2023, at selected locations with remaining uncertainty.

Using a combination of the data above, a tabulation of identified artificial penetrations within the AoR has been created and is summarized in Table 3-16. The identified artificial penetrations can be found on Figure 3-19. Available records for the identified artificial penetrations can be found in Appendix C.

Table 3-16: Summary of Artificial Penetrations within AoR

#	Well Name	State/ Federal Well ID (API Number)[1]	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
1	Above-Zone Monitoring Well No. 01 Bead Farm Co. #1	4224532908	Project Monitoring Well	Active	10/15/2023 Recompleted 02/07/2025	8,664	29.999222, -94.297364	Yes
2	Broussard JE Jr-1[2]	4224502193	Dry Hole	P&A	2/10/1958	9,050	29.996539, -94.287435	Yes
3	Broussard J. E. Etal-1	4224502194	Dry Hole	P&A	Unknown	2,518**	29.999730, -94.274070	No
4	BFC-1 Rig Supply Water Well #1	645970	Water Rig Supply	In Use	8/11/2023	290*	29.999028, -94.298056	No
5	D. S. Wier	Not Available	Water Supply	P&A	1941	7*	30.001389, -94.270833	No
6	Labelle Properties Ltd #1	4224532913	Project Injection Well No. 01	Active	06/23/204	8,672	29.999678, -94.285108	Yes
7	Bead Farm Co. #2	4224532911	Project Injection Well No. 2	Active	07/15/2024	8,752	29.991017, -94.298036	Yes
8	Bead Farm #3	4224532912	Project Injection Well No. 3	Active	08/05/2024	8,565	30.011778, -94.297858	Yes
9	Bead Farm Company #4	4224532914	Project Monitoring Well	Active	08/31/2024	8,383	30.021558, -94.293978	Yes
10	Rose Rig Supply Water Well #1	670175	Water Rig Supply	Active	6/14/2024	300*	29.999857, -94.28321	No

11	Rose Rig Supply Water Well #2	670177	Water Rig Supply	Active	7/2/2024	300*	29.990716, -94.298632	No
12	Rose Rig Supply Water Well #3	674757	Water Rig Supply	Active	7/19/2024	300*	30.012428, -94.297908	No

[1] Readily available well identification numbers provided from public data sources up to March 19, 2025.

[2] API:42245E070100 and an associated dry hole (API: 245) were determined to be associated with Broussard JE Jr-1 and not separate wellbores.

13	Rose Rig Supply Water Well #4	675893	Water Rig Supply	Active	8/15/2024	300*	30.021947, -94.294199	No
14	USDW Monitoring Well No. 1	678487	USDW Monitoring Well	Active	8/20/2024	330*	30.030833, -94.310556	No
15	USDW Monitoring Well No. 2	678489	USDW Monitoring Well	P&A***	8/20/2024	440*	30.0025, -94.274444	No
16	USDW Monitoring Well No. 3	678491	USDW Monitoring Well	Active	8/20/2024	330*	29.9875, -94.298889	No
17	USDW Monitoring Well No. 2R	683826	USDW Monitoring Well	Active	11/9/2024	320*	30.0025, -94.274444	No
18	Shallow Groundwater Well #1	689934	Monitoring Well	Active	9/19/2024	25*	29.99927, -9428565	No
19	Shallow Groundwater Well #2	689935	Monitoring Well	Active	9/17/2024	25*	29.99062, -94.2986	No
20	Shallow Groundwater Well #3	689936	Monitoring Well	Active	9/17/2024	25*	30.01238, -94.29797	No
21	Shallow Groundwater Well #4	689937	Monitoring Well	Active	9/18/2024	20*	30.00268, -94.27403	No

Notes:

ID = identification

*Water well datum is BGL
**KB not available in historical records
***Casing collapsed above water table, couldn't collect sample, redrilled as 2R in same location

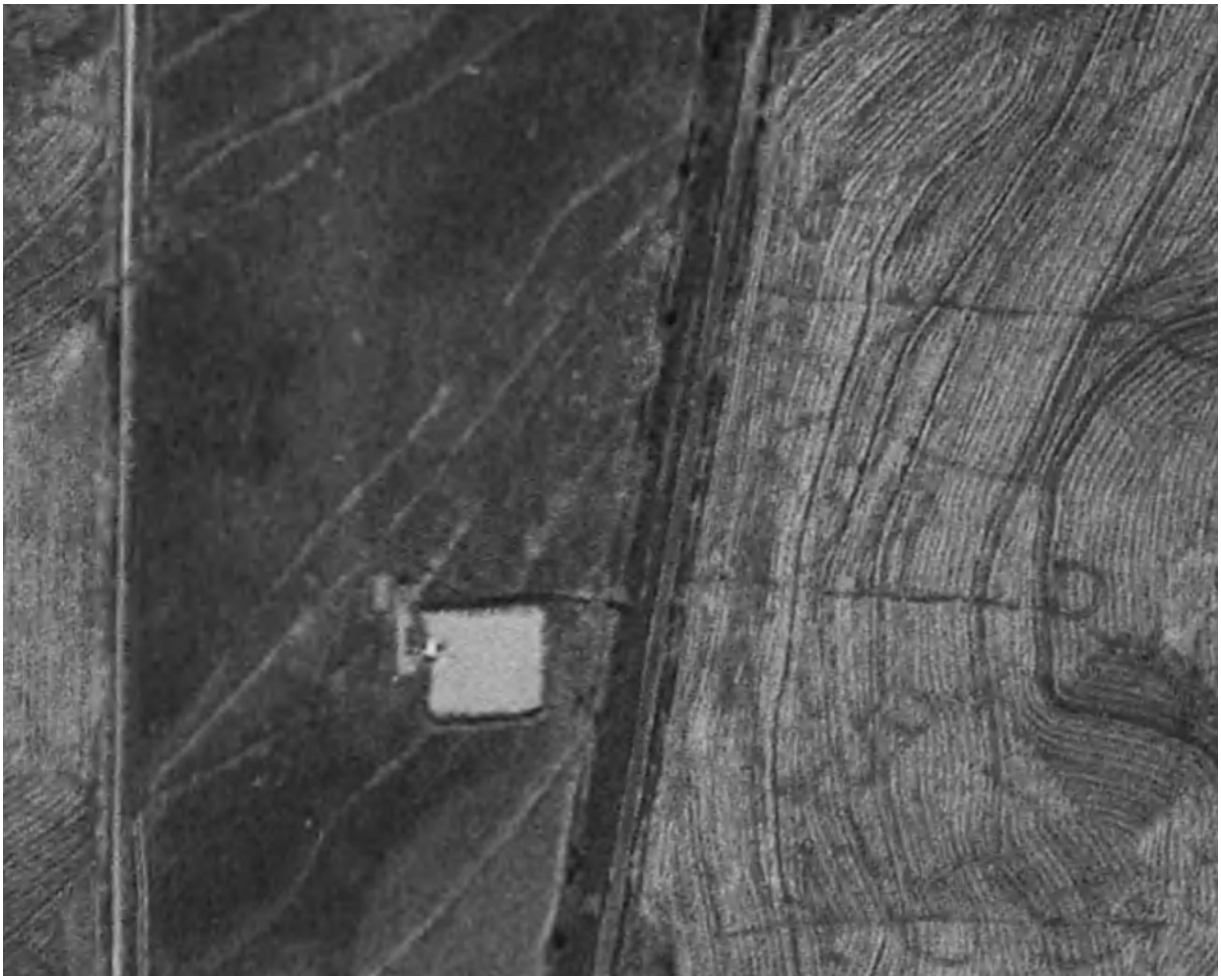
Review of Historical Aerial Photographs

ExxonMobil conducted a review of readily available historical aerial photographs for selected legacy wells to assess well location and completion dates. Two legacy wells within the AoR and one legacy well outside of the AoR were assessed using available historical aerial photographs from 1952 and 2020.
The Broussard Trust-1 (API: 4224500111) well location is located outside of the AoR and was completed below the UCCZ. Information on this well is provided for completeness purposes only to illustrate the standard of care taken to identify legacy wellbores for corrective action purposes. Based on the available imagery, a well pad and pit were observed in the 1952 historical aerial photograph (Figure 3-20), confirming the presence and location of this well. By the time that a 1976 aerial photograph was taken, the well pad appears to be revegetated and the pit remained visible showing that the well had been drilled but was probably not abandoned by that time. The pit was observed until at least the 1995 aerial photograph.

Figure 3-20: 1952 Historical Aerial Photograph of Broussard Trust-1 (API: 4224500111)

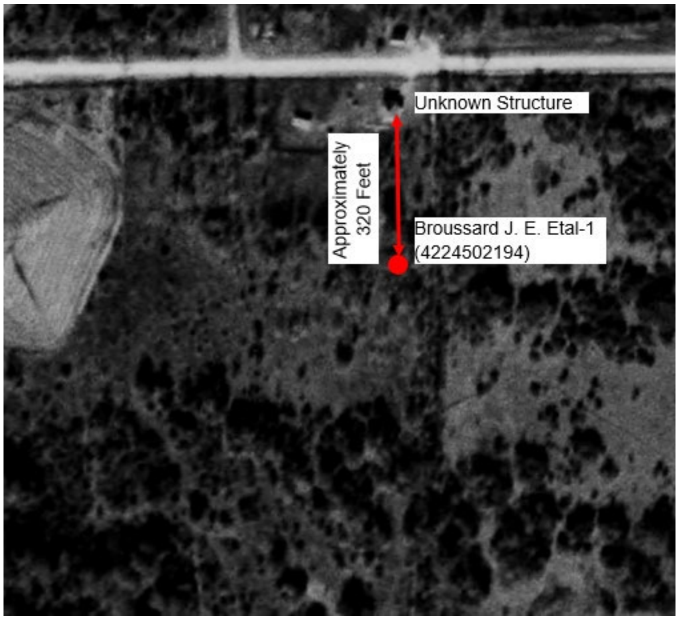
The Broussard JE Jr-1 (API: 4224502193) well location was identified in the 1959 historical photograph (Figure 3-21). In the 1960 aerial photograph, the pad appears to have been reclaimed with revegetation in progress.

Figure 3-21: 1959 Historical Aerial Photograph of Broussard JE Jr-1 (API: 4224502193)



The Broussard J. E. Etal-1 (API: 4224502194) location identified no well surface impacts and construction features within the historical aerial imagery. An unknown structure was identified to the north of the known coordinates along Lawhon Road in the 1952 historical photograph (Figure 3-22). In the 1957 aerial photograph, the structures appear to have been removed with revegetation of the area in progress. The relationship between the structure and the well location is uncertain. The well location was not confirmed as being a drilled well location.

Figure 3-22: 1952 Historical Aerial Photograph of Broussard J. E. Etal-1 (API: 4224502194)



Physical Records Review

For wells within the AoR, ExxonMobil obtained copies of physical records for Broussard JE Jr-1 (API: 4224502193). The remaining records were reviewed through digital copies on the RRC online databases, Enverus Drilling Info, and IHS Energy Portal. These records can be found in Appendix C-5.

Aeromagnetic Survey

Due to the age of well development in the area, additional data collection was conducted in selected portions of the AoR, wherein additional insight into well locations or details was required to improve accuracy. Magnetic survey methods were used in 2023 to scan portions of the AoR for magnetic anomalies that are caused by subsurface features, which could include abandoned wellbores with iron or steel casing. The survey was completed on a prior model of the AoR, which has since been updated. The survey was conducted by Sander Geophysics Ltd. A drone was flown across targeted portions of the AoR to identify the presence or absence of magnetic anomalies. Figure 3-23 shows the survey grid and the magnetic anomalies from the survey. The technical report from this survey can be found in Appendix C-4. As shown on Figure 3-24, well heads, pipelines, and farm equipment present during the survey are displayed according to the key. Well heads are generally high amplitude positive (red) anomalies with wavelengths ranging from 150 meters to 500 meters (in this region). Pipelines are a series of positive/negative anomalies (red and blue) based on flight line spacing for the survey. Negative anomalies are generally due to the base of a magnetic source indicating near surface nature with limited depth extent. Most of the lower amplitude and shorter wavelength positive anomalies were noted to be due to surface culture (e.g., culverts and bridges).
Figure 3-23 shows the aeromagnetic survey results superimposed with the artificial wells identified. Based on this review, no additional legacy well locations were identified.

Figure 3-23: Aeromagnetic Survey Grid and Magnetic Anomalies within AoR

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Figure 3-24: Aeromagnetic Survey Analysis of Anomalies

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ExxonMobil attempted to conduct an in-person reconnaissance survey for two legacy well locations identified in Table 3-16 for Broussard JE Jr-1 (API: 4224502193) and Broussard J. E. Etal-1 (API: 4224502194), and one well that was outside the AoR for Broussard Trust-1 (API: 4224500111). The intent of the survey was to address uncertainty regarding the existence of these reported legacy wells and verify their presence or absence. ExxonMobil worked with a geophysical surveyor, Ground Penetrating Radar Services, Inc. (GPRS), to conduct survey assessments. GPRS utilized a frequency domain electromagnetic induction meter for the geophysical surveys. Two of the three locations, Broussard JE Jr-1 (API: 4224502193) and Broussard J. E. Etal-1 (API: 4224502194), were flooded due to farm irrigation activities. The presence of standing water negates the electromagnetic induction signal; therefore, they could not be surveyed. A visual inspection of the location was recorded including looking for apparent features that may have indicated the presence of a legacy well pad or mud pit. None were apparent at the three flooded well locations.

The results of the in-person survey completed for the Broussard Trust-1 (API: 4224500111) well location are presented in Figure 3-25. The geophysical survey image indicates findings across four different frequencies. These are typical frequency formats utilized for detecting metallic objects. The orange feature on the figure running east to west indicates a very bright linear reaction that is produced by a pipeline running across the northern portion of the area. ExxonMobil confirmed the presence of multiple pipelines in this area via the RRC GIS Database. The pipelines were identified as active and operated by Energy Transfer Company and Mobil Pipe Line Company. These pipelines reportedly transfer crude oil and high volatile liquids. The yellow feature on Figure 3-25 shows a positive reaction in the southwest portion of the survey, which appears to be a linear feature (such as a flowline or pipeline) running generally from northwest to southeast. The blue area indicates a negative reaction near the center of the area, which indicates an area of less conductivity than the surrounding data. The blue negative reaction can indicate soil features such as compaction for dirt foundations or other soil disturbances such as the presence of a hole in the ground. The records for the Broussard Trust-1 (API: 4224500111) well indicated this location was a dry hole that was plugged and abandoned after it was drilled in 1937, so there would be no metal anomalies expected to exist within the wellbore if it was a dry hole where casing was not run or was pulled. It is likely that the historical location of the well is in the area identified by the negative reaction in blue in the center of the survey area.

Figure 3-25: GPRS Geophysical Survey Image of Broussard Trust-1 (API: 4224500111)

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Review of Abandoned Well Plugging Records

ExxonMobil conducted an evaluation of the information available for the artificial penetrations listed in Table 3-16. The list of topics reviewed included:

- Well depth and completion;
- Well drilling date;
- Well abandonment date;
- Open hole or cased hole identification;
- Location of reported plugs;
- Casing and cementing records;
- Records of mechanical integrity tests or logs performed; and
- Well deviations.

The wells listed on lines 3 through 5 and 10 through 22 in Table 3-16 were found to have completion depths shallower than the UCCZ; therefore, no further assessment for corrective action was warranted because the wells have not penetrated the UCCZ. Wells 1 and 2 were identified as penetrating the UCCZ and subject to an assessment of plugging records and potentially corrective action for deficiencies. Record availability for the two artificial penetrations requiring corrective actions were sufficient for determining the corrective action plans. As however, this did not impact the corrective action plan.

Summary of Artificial Penetrations Tabulation

ExxonMobil conducted a thorough assessment of the potential for artificial penetrations to be present within the AoR. Wells and boreholes completed above the UCCZ were determined to pose no hypothetical risk to function as a vertical conduit from the injection zone. For those artificial penetrations that were completed below the UCCZ, multiple sources of information were reviewed, and the relevant information was analyzed in detail [40 CFR 146.84(c)(2)]. Table 3-16 presents a summary of the artificial penetrations of interest for developing the Corrective Action Plan. The following summarizes the findings to date for the three legacy wells (excluding non-applicable water wells) identified in the AoR:

- Bead Farm Co. #1 (4224532908): This well is within the CO_2 plume and within the pressure front. ExxonMobil drilled this well in October 2023 as a stratigraphic well for this Project. The stratigraphic well has since been converted to an above-zone monitoring well to conduct monitoring above the confining zone. The well is cased and cemented with top of cement above the UCCZ utilizing CO_2-compatible cement. An additional balanced cement plug with CO_2-compatible cement was placed at the UCCZ inside the casing.
- Broussard JE Jr-1 (4224502193): This well is within the CO_2 plume and within the pressure front. The well was drilled in the 1950s and completed as an open hole. A CO_2-compatible cement plug has been set at the UCCZ. An additional CO_2-compatible cement plug has been set at the USDW, the Base of Usable Quality Water (BUQW), the shoe casing, and the Superior Quality Water (SQW).
- Broussard J.E. Etal – 1 (4224502194): The well is within the CO_2 plume and within the pressure front. The well is an open hole well drilled to a reported 2,518 ft KB. The well does not penetrate the UCCZ and is not considered a risk for potential brine crossflow.

Corrective Action Plan for Artificial Penetrations

ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit because it was not plugged, it was plugged and abandoned improperly, or not plugged in a manner that mitigates the movement of CO_2 or other fluids that could potentially endanger USDWs as required by 40 CFR 146.84(c) and (d).

For the well identified with plugging deficiencies, the basis for the corrective action strategy is to re-enter each well that has insufficient proof that it has been sealed to reduce the potential for vertical flow through the UCCZ and to install cement barriers inside the casing to mitigate migration potential through the casing. The CO_2-compatible cement material has been used where appropriate in accordance with 40 CFR 146.84(d).

Tabulation of Artificial Penetrations for Corrective Action

Figure 3-26 shows the location of the wells identified for corrective action in relation to the five-year pressure front and CO_2 plume. Table 3-17 lists Bead Farm Co. #1 (API: 4224532908) and Broussard JE Jr-1 (API: 4224502193) as identified for corrective actions prior to injection based on the expected arrival times of the CO_2 plume and pressure front.

As described in the Testing and Monitoring Plan of this Application, direct and indirect monitoring technologies will be used to track the CO_2 plume and pressure front. A planned reevaluation of the AoR will occur after five years of injection and throughout the lifecycle of the Project. If at any time the rate of the CO_2 plume or pressure front expansion is predicted to impact additional artificial penetrations that may be found, the Corrective Action Plan will be amended to include the necessary corrective action to reduce the potential for USDW endangerment in accordance with 40 CFR 146.84(b)(2)(i)–(iv).

Analysis of Wells Identified for Corrective Action

Table 3-18 summarizes the available information concerning the borehole or well completion features and the P&A activities, as appropriate. ExxonMobil reviewed this information and determined the specific defects that require mitigation under 40 CFR 146.84(c) and (d).

[redacted]

Table 3-17: List of Artificial Penetrations and Schedule for Corrective Action

Well Name	API Number	Latitude, Longitude (NAD83)	Pressure Plume	CO2 Plume	Casing	Schedule
Bead Farm Co. #1	4224532908	29.9992220	Year 1 (Upper Frio)	Year 6 (Fleming 3)	Casing Present	Pre-operation

		-94.2973637				
Broussard JE Jr-1	4224502193	29.996050 -94.286120	Year 13 (Upper Frio)	Year 1 (Upper Frio)	Open Hole	Pre-operation

Table 3-18: Summary of P&A Deficiency for Wells Penetrating UCCZ

Well Name	API Number	Apparent Deficiency or Uncertainty Based on Review of Available Information			Summary of Corrective Action
		Casing Records at UCCZ	USDW plug(s) installed	UCCZ plug(s) installed	
Bead Farm Co. #1	4224532908	Cased	No	Yes	Pump inside casing with CO2-compatible cement plug(s) across the UCCZ, convert wellbore to Above- Zone Monitor Well
Broussard JE Jr-1	4224502193	Open borehole	Yes	Yes	Pumped open hole CO2-compatible cement plug(s) at UCCZ, USDW, BUQW, casing shoe, and SQW.

Corrective Action Sequence Plan

The following corrective action sequences were undertaken in accordance with 40 CFR 146.84(c)(3) for the two artificial penetrations listed in Table 3-17. The outlined actions are based on completed plugging activities for the stratigraphic well or to plug deficiencies potentially present in the legacy well based on the available records (Table 3-18). Each artificial penetration in the CO2 plume has been re-entered, and if sufficient barriers are not present, each well has had the appropriate barriers installed during the corrective action P&A field operations. The barriers have been established at the UCCZ, the surface casing shoe, the base of the lowermost USDW, and wellhead surface. The barrier at the UCCZ was constructed of CO2-compatible material consistent with 40 CFR 146.84(d).

A general approach for well re-entry and corrective actions is summarized in the sections below. A detailed summary of the corrective action sequence for each well and dates when actions were taken are presented in Table 3-19 and as specific well schematics for each well to be re-entered in Appendix C.

Field Verification of Well Status

For each well that was field verified via re-entry, the casing and cement plug features and potential for sufficient isolation were evaluated using standard industry tools. ExxonMobil completed a visual inspection of cement evidence at surface before well re-heading, conducted a casing pressure test, and if needed, completed a cement sheath evaluation log. In accordance with 40 CFR 146.84(d), the actual deficiencies of the casing or cement identified during tests would be the basis for the corrective action sequences pursued during field operations to seal at each artificial penetration.

Preparing the Surface Location

Prior to mobilizing at a well location, ExxonMobil conducted an initial site visit to identify current site access and wellhead conditions. If required, a subsurface survey was completed utilizing ground penetrating radar to identify the well location. If legacy equipment remained on the site, the equipment was removed prior to mobilization. Surface piping and electrical components were assessed and removed from the site locations. Additionally, access roads to the area surrounding the pad and wellhead access improvements were evaluated to facilitate safe entrance and egress along with rig operations.

If a sign or marker was present, the first step was to confirm that the API number on the plat corresponded to the well where mobilization was taking place to complete corrective action operations. After the P&A marker or exposed metal plate was removed, necessary equipment would be rigged up on the well. The cement surface plug of the well would be drilled out and the hole conditioned sufficiently for well logging tools to be utilized within the well on an as-needed basis.

ExxonMobil followed required notification requirements prior to commencing remedial field activities that may take the form of workover or drilling operations. At least five days prior to commencement of well plugging operations, ExxonMobil notified the RRC via a request for approval of the proposed procedure for plugging the well using Form W-3A. ExxonMobil also notified the RRC at least four hours prior to the start of plugging operations. Copies of the notifications and of field operational records provided to the state are provided to EPA Region 6.

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Reporting Completion of Corrective Action

After completing the corrective actions and re-plugging a well, a W-3 plugging report will be submitted to the RRC within 30 days of plugging, including the W-15 cementing report. Records of the corrective actions will be submitted to the UIC Program Director, with copies provided to EPA Region 6.

<u>Site-Specific Review of Corrective Actions</u>

Table 3-19 provides the corrective action sequences for the two wells. Appendices C-1 to C-2 provide the well schematics of each legacy well that have been re-entered for evaluation and re-plugging, which were developed based on the historical information and completion of the associated proposed corrective actions.

Table 3-19: Summary of Corrective Actions for Wells Penetrating the UCCZ

[redacted]

[redacted]

<u>Stratigraphic Well P&A and Conversion</u>

The following section outlines the plan for the P&A and conversion of the stratigraphic well referred to as Bead Farm Co. #1. The stratigraphic well was completed in the immediate vicinity of the injection wells for the purpose of gathering site-specific physical and chemical information on the confining and injection zones as well as to conduct conductivity testing. Once the data gathering activities were completed, the stratigraphic well was plugged across the UCCZ and converted to an above-zone monitoring well to obtain fluid samples from first permeable interval above the UCCZ.

Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil has complied with reporting and notification provisions for stratigraphic wells drilled in Texas in accordance with RRC. The following notifications and permits were submitted:

- Bead Farm Co. #1: Complete Cementing Report Form W-15 and Recomplete Report Form W-2 to be filed with the RRC District Office 3 within 150 days after recompletion.

Broussard JE Jr-1: Submit W3 plugging report with necessary attachments within 30 days after plugging operations are completed. ExxonMobil has also submitted these records to the UIC Program Director for completeness purposes.

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Plan for Site Access

In accordance with 40 CFR 146.84(b)(2)(iv) and 40 CFR 146.84(d), ExxonMobil has negotiated land access for each of the artificial penetrations identified for corrective action. Research to identify the well owners via regulatory databases has been completed and necessary access rights secured. The limited number of legacy wells requiring corrective action prior to commencing operations is a significant factor in mitigating the risk for the Project.

As shown in Table 3-20, an access agreement is in place for the Bead Farm Co. #1 stratigraphic well and Broussard JE Jr-1. Corrective actions for these wells have been completed. If appropriate and necessary, ExxonMobil will seek plugging orders from the RRC in accordance with Subchapter C of Chapter 89 of the Texas Natural Resource Code to obtain access for corrective actions.

If the AoR reevaluation conducted at the minimum schedule of once every five years identifies the potential for corrective action requirements at additional wells, ExxonMobil will promptly begin review of the additional wells in accordance with the process described this Corrective Action Plan. If future site access issues are identified for wells identified for corrective action, ExxonMobil will notify the UIC Program Director.

Table 3-20: Summary of Access Milestones for Corrective Action

Well Name	API Number	Proposed Actions for Access Rights	Anticipated Date of Final Access Agreement
Bead Farm Co. #1	4224532908	ExxonMobil is the operator of this well. Wellbore access is in place. Surface access agreements are in place with the surface owner this well is located on. These rights run with land ownership. If the land is conveyed to a third party, the surface access rights will remain in place.	Completed

Broussard JE Jr-1	4224502193	The last operator of this wellbore does not have an active Organization Report (P-5) status with the RRC. ExxonMobil conducted an open records request for the well and confirmed the owner of the well does not have an active P-5. ExxonMobil has acquired the required RRC permits for re-entering the well and completing corrective actions. ExxonMobil has confirmed site access with the landowner Labelle Properties, Ltd to complete the corrective actions.	Acquired on March 31, 2023

AoR Reevaluation Plan and Schedule

Frequency of AoR Reevaluation

ExxonMobil adopts the minimum frequency of five years for the AoR and Corrective Action Plan reevaluation. Information gathered from implementation of the Section 5 – Testing and Monitoring Plan will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO2 plume and pressure front migration.

If an alteration of the AoR reevaluation frequency of a minimum of every five years is recommended, the change in frequency will be aligned with the data evaluation and findings relative to the degree of protectiveness of USDW and approved by the UIC Program Director. ExxonMobil acknowledges that any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate. ExxonMobil also acknowledges the requirement in 40 CFR 146.84(b)(2)(i) of "The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review."

Content of the AoR Reevaluation

The requirements for AoR reevaluation are specified in 40 CFR 146.84(e) and include the following considerations:

• Reevaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);

• Identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

• Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d); and

• Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

Conditions Warranting AoR Reevaluation

The monitoring and operational conditions that would warrant a reevaluation of the AoR prior to the next scheduled reevaluation [i.e., the minimum fixed frequency established in 40 CFR 146.84 (b)(2)(i)] are outlined below. These triggering events are based on a review of the hydrogeological site characteristics, the AoR and plume model results, and the pre-operational and operational plans for the Project. For each triggering event, Table 3-21 provides a summary of how the monitoring and operational data will be used to inform an AoR reevaluation and how corrective action will be conducted to reduce the potential for threats to USDW, if any arise. If an AoR reevaluation were to occur, corrective actions will be reevaluated.
Table 3-21 provides a list of the potential triggers for an AoR reevaluation consistent with the requirements of 40 CFR 146.84(b)(2)(ii).

Table 3-21: Triggers for AoR Reevaluation

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
1	Compliance with minimum fixed frequency of at least once every five years [40 CFR 146.84(b)(2)(i)].	The AoR may need to be reevaluated more frequently than the minimum fixed frequency based on changes in operations or results from site monitoring that differ from model predictions. In these cases, the schedule for AoR reevaluation may be updated appropriately.	ExxonMobil will notify the UIC Permit Manager that a more frequent AoR reevaluation is warranted based on changed conditions. This notification will form the basis of a permit modification and updates to the relevant portions of the Application.
2	changes in operations that mandate AoR reevaluation under 40 CFR 146.84(c) as outlined below.	AoR reevaluation will be informed by both planned changes to operations and by testing and obtaining monitoring data that signal potential unexpected CO2 plume migration impacting the extent of the AoR. Examples may include installation of an additional injection well or identification of new offset well installation by third parties. Certain short-term operational changes, such as temporary well shut-ins, are not expected to warrant AoR reevaluation.	ExxonMobil will notify the UIC Program Director of the plan for changes in operations by pre- permitting engagement and the necessary modifications to the permit. The UIC Program Director may require an AoR reevaluation prior to approving such operational changes or changes may be allowed to occur prior to reevaluation of the AoR. The AoR reevaluation will be submitted to the UIC Program Director within an agreed-upon timeframe of instituting such changes, as described in the AoR and Corrective Action Plan.
2A	Plan to change injectate composition mixture.	Re-run the reservoir plume model with a new composition mixture. If plume extents increase, reevaluate the AoR.	Within one month of composition change, notify the UIC Program Director of change and potential need to reevaluate AoR.

2B	New offset operations are established.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	Within one month of commencement of new operations, notify the UIC Program Director of change and potential need to reevaluate AoR.
2C	Measured supercritical gas saturation is different than modeled gas saturation.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2D	An injection well exhibits an anomalous change in surfacepressure for a sustained period of time.	Incorporate new pressure information and re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2E	An injection well exhibits an anomalous change in bottomhole temperature for a sustained period of time.	Incorporate new temperature information and re- run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2F	Casing or tubing leak detected by casing integrity logging.	Investigate possible tubing leak and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
2G	Positive pressure loss in tubing annulus.	Investigate possible pressure loss and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
3	Results from site monitoring that differ from model predictions [40 CFR 146.84(b)(2)(ii)] as outlined below.	An evaluation of monitoring data [required under 40 CFR 146.90] indicates that CO2 and/or pressure front migration is different than that predicted by the current AoR delineation model and, therefore, warrants an AoR reevaluation.	Notification of difference to UIC Program Director within one month of confirmed findings.

		The following examples provide specific criteria for differences in monitoring data and model predictions that may trigger an AoR reevaluation [40 CFR 146.84(b)(2)(ii)].	

3A	Seismic event greater than M3.0 within 5.6-mile radius of injection well.	Evaluate pressure and temperature data relative to operating limits and pressures in the in-zone monitoring well. Evaluate the need to enhance monitoring program to confirm extent of CO_2 plume.	If evidence of mechanical integrity issues may cause an endangerment to USDW cease injection, notify the UIC Program Director within 24 hours of the determination and implement the emergency and remedial response plan approved by the UIC Program Director. Operations will resume upon UIC Program Director concurrence that necessary remedial or corrective measures have been taken such that the risk to the USDW is as low as reasonably practicable.
3B	Annual plume migration survey identifies the plume migration direction that is different then the modeled direction of migration.	Re-run the reservoir plume model incorporating injection well pressure and temperature data for calibration and other available information on plume migration and reevaluate the AoR.	Within one month of detection, ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.
3C	The horizontal CO_2 plume migration rate is different than predicted.	Re-run the reservoir plume model incorporating injectors data for calibration and new information on plume migration and reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.

3D	Sustained acoustic anomaly, which is unrelated to oil and gas activity in the area, detected by seismic survey or noise log.	Investigate seismic survey data anomaly and decide if the change triggers contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on seismic survey data analysis and or results from contingency monitoring.
3E	Statistically significant increases of indicator parameter concentrations above baseline for USDW samples of TDS, major cations and anions, CO2 concentration, isotopic values, or pH.	Resample fluid sample that contained the elevated concentrations and compare resample results with numerical criteria for trends and/or exceedances of target concentrations.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on resampling results and data evaluation.
3F	The presence of separate-phase CO2 in the sampled fluids above the confining zone, fluids above the confining zone,but below the lowermost USDW resulting from CO2/fluid migration out of the injection zone.	Investigate possible migration pathways and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.

ATTACHMENT 3: FINANCIAL RESPONSIBILITY DEMONSTRATION

Facility Information

Facility name:	Rose Carbon Capture and Storage Project Rose CCS Nos. 1, 2, and 3 wells
Well location:	Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Financial Assurance

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Rose Carbon Capture and Storage (CCS) Project (Project) in Jefferson County, Texas to sequester a maximum of 5 million metric tonnes per annum of carbon dioxide (CO2) using three injection wells over an injection period of up to 13 years. The predicted total CO2 storage is 53 million metric tonnes. Under the Code of Federal Regulations, Title 40, Section 146.85 [40 CFR 146.85], owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities. [1] Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Rose CCS Project (Rose Site[2]).

The sections that follow summarize the Project's GS activities, as well as the qualifying financial instrument that ExxonMobil proposes to use, to demonstrate financial responsibility for the following Project phases: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care (PISC) and Site Closure; and (4) Emergency and Remedial Response (ERR).

[1] *The use of the term "geologic sequestration activities" is unique to this section of the Application. It is used to provide additional clarity on which activities of the Project's lifecycle necessitate financial assurance from those that do not, consistent with EPA guidance for financial assurance.*

[2] *Reference to the Project as the "Rose Site" is used in this section of the Application to distinguish between this Project and other ExxonMobil project applications undergoing simultaneous financial assurance review.*

Facility Information

Facility Name:	ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) – Rose CCS Project

Facility Contact:	[redacted]
	ExxonMobil Low Carbon Solutions Onshore Storage LLC
Project Site Name:	Rose Carbon Capture and Storage Project
Project Location:	Jefferson County, Texas
Well Name and Number	Labelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)
County	Jefferson
Location (RR D, S, A)	Railroad District 3, Section 42, Abstract 874
Latitude / Longitude (NAD83)	29.999678 / -94.285108
American Petroleum Institute	4224532913

Financial Assurance Demonstration

Per 40 CFR 146.85(a)(1)(v), ExxonMobil requests approval from the Underground Injection Control (UIC) Program Director, or their designee, to use a corporate guarantee from Exxon Equity Holding Company (EEHC) for purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, PISC and Site Closure, as well as ERR. EEHC is an indirectly wholly owned subsidiary of Exxon Mobil Corporation (EMC). EEHC provides financial support to or on behalf of EMC's affiliates. EEHC maintains significant intercompany relationships with EMC and its affiliates as shown in Figure 9-1, and as of December 31, 2023, the company had interest-bearing deposits with EMC and its affiliates totaling [redacted] The deposit balances are current and can be called upon demand. See Appendix J-1 for a copy of the independently audited financial statements for EEHC.

Figure 9-1: Corporate Structure

[redacted]

In support of the financial assurance demonstration, EEHC has provided a corporate guarantee to

ExxonMobil, which is consistent in form to the corporate guarantee language included in Appendix B of the U.S. Environmental Protection Agency's (EPA) July 2011 guidance document (EPA, 2011). See Appendix J-2 for a copy of the executed corporate guarantee. As shown in Table 9-1, EEHC satisfies both Part 1 and Part 2 of the corporate financial test criteria in 40 CFR 146.85(a)(6)(v).

Table 9-1: Financial Coverage and Threshold Criteria for EEHC, as Guarantor to ExxonMobil for the Rose Site

Financial Coverage / Threshold Requirement per 40 CFR 146.85(a)(6)(v)[3]	EEHC Financial Measure
Part 1	
1. Tangible net worth of at least $100 million?[4]	Yes
2. Net working capital at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	Yes
3. Tangible net worth of at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	Yes

[3] As stated in Note 3 of EEHC's independently audited financial statements, Deposits receivable from Exxon Mobil Corporation and affiliates are current and can be called upon demand. All other assets were considered "non-current" for the purposes of this analysis. In addition, all liabilities were considered "current" since the audited financial statements do not differentiate current from non-current liabilities.

[4] ExxonMobil recognizes that 40 CFR 146.85(a)(6)(v) requires that its guarantor meet a Tangible Net Worth of an amount approved by the UIC Program Director. For purposes of this financial assurance demonstration, EEHC affirms that it maintains a Tangible Net Worth of at least $100 million, per the recommended threshold included in EPA's July 2011 Class VI financial responsibility guidance (p. 15).

Financial Coverage / Threshold Requirement per 40 CFR 146.85(a)(6)(v)[3]	EEHC Financial Measure
4. Assets in the United States amounting to at least 90% of total assets <u>or</u> Assets in the United States amounting to at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR cost estimate?	Yes
Part 2	
5. Total liabilities to net worth ratio less than 2.0?	Yes
6. Current assets to current liabilities ratio greater than 1.5?	Yes
7. Sum of net income plus depreciation, depletion, and amortization to total liabilities ratio greater than 0.1?	Yes
8. Current assets minus current liabilities to total assets ratio greater than *minus* 0.1?	Yes
9. Net profit (revenues minus expenses) greater than $0?	Yes

Appendix J-3 is a completed letter from CBI [redacted] of EEHC, serving as the chief financial officer of EEHC, that demonstrates the company's ability to meet the requisite financial coverage and threshold criteria, per 40 CFR 146.85(a)(6)(v).

Appendix J-3 is consistent in form to the "Letter from Chief Financial Officer" included in Appendix B of the EPA's July 2011 guidance document.[5]

Consistent with the EPA's July 2011 guidance, ExxonMobil provides this demonstration of fiscal responsibility with the understanding that the financial instruments referenced herein will be updated and verified no less than annually. As each GS activity phase is initiated, ExxonMobil will confirm that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding costs prior to initiating the Project phase.

Furthermore, per Texas Administrative Code §5.205, ExxonMobil requests approval from the Texas UIC Program Director, or their designee, to use a bond for purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, PISC and Site Closure, as well as ERR. The required documentation to satisfy this requirement is in Appendix J-5.

Estimated Coverage Amounts

The total current cost estimate for the Project's GS activities necessitating financial assurance at the Rose Site is $23,631,000 in 2025 dollars. This total cost estimate assumes the hiring of independent, third-party contractors to perform the required activities for each Project phase. The cost estimate is separated into the following phases:

1. Phased-Corrective Action for artificial penetrations (legacy wells) in the Area of Review (AoR) remaining after initiating operations;
2. Well Plugging[6] to occur after 13 years of site injection;
3. PISC: beginning after 13 years of site injection and ending with Site Closure 50 years after injection ends; and
4. ERR: beginning after 13 years of site injection and ending with Site Closure .

[5] *op.cit. See B-19 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates).*
[6] *Financial responsibility coverages for well plugging reflect the current estimated cost for plugging the three injection wells and four monitoring wells related to the Project.*

Table 9-2 summarizes the total estimated cost of performing each GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the Application process and assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each GS activity. These values are subject to change during the life of the Project to account for inflation of costs and changes to the Project that may affect the cost of covered activities. Per 40 CFR 146.85(c), during the active life of the Project, ExxonMobil will adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial assurance instrument. In addition, ExxonMobil will provide to the UIC Program Director written updates of adjustments to the cost estimate within 60 days of any amendments to the AoR and Corrective Action Plan [40 CFR 146.84], the injection well plugging plan [40 CFR 146.92], the PISC and Site Closure Plan [40 CFR

146.93], and the emergency and remedial response plan (ERRP) [40 CFR 146.94].

ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its revised demonstration of financial responsibility to the UIC Program Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Program Director, or their designee.

Table 9-2: Summary of Financial Assurance Coverage Values by GS Activity

GS Activity	Estimated Financial Assurance Coverage Value
Corrective Action	$0
Well Plugging	$3,603,000
PISC and Site Closure	$11,420,000
ERR	$8,608,000
TOTAL	$23,631,000
Note: Section 3 – Area of Review and Corrective Action Plan, Section 5 – Testing and Monitoring Plan, Section 6 – Injection Well Plugging Plan, and Section 8 – Emergency and Remedial Response Plan provide detailed discussion of work to be undertaken, which forms the cost basis for the financial assurance coverage values summarized in this table	

Corrective Action

The Corrective Action Plan is discussed in detail in Section 3 – Area of Review and Corrective Action Plan. Per the requirements of 40 CFR 146.84, the plan specifically outlines both a plugging plan for the artificial penetrations found within CO2 plume and brine pressure front and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned activities at the Project, workovers on the legacy wells found to have sufficient deficiency as to represent a potential loss of CO2 or brine containment will be re-entered and plugged prior to receiving approval to inject from the UIC Program Director. No corrective actions are expected to be needed beyond the model-predicted five-year extent of the AoR. The estimated financial assurance coverage value for this GS activity is shown in Table 9-3.

Per 40 CFR 146.84(a)(5)(ii), this financial responsibility demonstration will be updated annually to account for any changes in expected financial coverage values and to confirm that the financial instrument(s) then in place remain adequate for use.

Table 9-3: Summary of Corrective Action Costs Underpinning Financial Assurance Coverages

GS Activity	Estimated Financial Assurance Coverage Value
Corrective action on legacy wells (None identified)	$0
TOTAL	$0

Well Plugging

Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Project will meet the requirements of 40 CFR 146.92. The P&A plan for the injection wells was designed to reduce the potential for movement of CO2 or brine from the injection interval through the upper composite confining zone (UCCZ) and toward underground sources of drinking water (USDWs).

A detailed P&A plan is discussed in Section 6 – Injection Well Plugging Plan. In alignment with the requirements for the P&A plan, the estimated financial assurance coverage value includes costs for logs/wireline to be run in the wellbore before cementing occurs, if necessary. CO2- compatible cement will be used to set the cement plug for the first 100 feet of the UCCZ, followed by additional plugs at the base of the lowermost USDW and at the well surface. The expenses relating to personnel and equipment have been accounted for in Table 9-3.

Monitoring Well Plugging

P&A of the one in-zone monitoring well, one above-zone monitoring well, and three USDW monitoring wells associated with the Project will also meet the requirements of 40 CFR 146.92. As detailed in Section 6 – Injection Well Plugging Plan, the P&A of the monitoring wells was designed to protect USDW from potential endangerment. The estimated financial assurance coverage value for this GS activity includes the costs for logs and wireline to be run in the in- zone monitoring well before cementing occurs to the extent necessary. The expenses relating to personnel and equipment have been accounted for in Table 9-4.

Table 9-4: Summary of Estimated Well Plugging Costs Underpinning Financial Assurance Coverages

GS Activity	Estimated Financial Assurance Coverage Value	Total
CBI [redacted]		[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	

GS Activity	Estimated Financial Assurance Coverage Value	Total
CBI [redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]		[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]		[redacted]
[redacted]		[redacted]
TOTAL*		$3,603,000

*Note: Rounded to nearest ten-thousands.

Post-Injection Site Care and Site Closure Plan

The PISC and Site Closure Plan has been designed to meet the requirements of 40 CFR 146.93. The estimated financial assurance coverage value for this GS activity includes the cost categories summarized in Table 9-5, while the plan itself is discussed in Section 7 – Post- Injection Site Care and Site Closure Plan.

Post-Injection Monitoring

As discussed in Section 5 – Testing and Monitoring Plan, surface seismic and pressure and temperature monitoring will be conducted during operation and after the end of injection to assess the integrity of the well and to track the migration of the CO2 plume and brine pressure front.

Site Closure Plan

Site closure will occur when the UIC Program Director has released the owner from PISC duties and the demonstration of non-endangerment for USDWs has been approved. The estimated financial assurance coverage value for this GS activity is summarized in Table 9-5 and reflects the expected amount to decommission and close the site.

Table 9-5: Summary of Estimated PISC and Site Closure Costs Underpinning Financial Assurance Coverages

GS Activity	Estimated Financial Assurance Coverage Value	Total
CBI [redacted]		[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]		[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]		[redacted]
[redacted]		[redacted]
TOTAL		$11,420,000
[redacted]		

Emergency and Remedial Response

The ERRP is discussed in Section 8 – Emergency and Remedial Response Plan and is designed to satisfy the requirements of 40 CFR 146.94, which necessitates an ERRP that describes actions ExxonMobil will take to address movement of injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and PISC periods.

The financial assurance coverage value for ERR is estimated to be $8,608,000 in 2025 dollars and is summarized in Table 9-6. This estimate assumes coverage for the following event-based risk activities at the Project: mechanical integrity of injection well casing or cement seal, artificial penetrations of the UCCZ, mechanical integrity of operating equipment, and natural features affecting sealing properties of the UCCZ. Details regarding the approach used to develop the risk-based scenarios, the levels of severity considered, and the actions to be taken to avoid, monitor, respond, and notify the occurrence of risk events are summarized in detail in Section 8.

Table 9-6: Summary of Estimated ERR Costs Underpinning Financial Assurance Coverages

GS Activity	Estimated Financial Assurance Coverage Value
CBI [redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
TOTAL	$8,608,000

ATTACHMENT 4: CONSTRUCTION DETAILS

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Well Construction Plan and Operating Conditions

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting this Underground Injection Control (UIC) Class VI permit application to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage (CCS) Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas, to sequester a maximum of 5 million metric tonnes per annum (MMta) of carbon dioxide (CO2) using three injection wells over an injection period of up to 13 years. The predicted total CO2 storage is 53 million metric tonnes. The Well Construction Plan and Operating Conditions (Section 4) of the permit application contains information on the well construction and operating conditions in compliance with the requirements of the Code of Federal Regulations, Title 40, Sections 146.82 and 146.86 [40 CFR 146.82 and 146.86] and Texas Administrative Code, Part 1 Title 16 Chapter 5.

The three injection wells were designed for the sole purpose of injection and storage of CO2 safely in the Upper Frio and Fleming Sand injection intervals at the Project site, and to contain the CO2 within the injection intervals, protecting underground sources of drinking water (USDWs). The formation properties of the injection intervals make the Project site an excellent candidate for injection of CO2, with high porosity, high permeability, and brine fluids that contain approximately 5,000 feet (ft) of gross vertical sand thickness. Interbedded and overlying shale layers confine the injection intervals from USDW.

The well materials were compatible with all fluids with which they may come into contact and the design considered the depth of all porous formations, as identified during site characterization. The well design and materials were also appropriate for the proposed operating parameters. The formation testing at the injection well locations filled potential gaps in available site characterization data and addressed key uncertainties in the Area of Review (AoR) delineation modeling.

The injection well construction specifications and testing plan were tailored to account for the data acquired from the logging, testing, and preliminary results from a stratigraphic well (Bead Farm Co. #1) that was completed in close proximity to the three injection sites in 2023. The stratigraphic well (Bead Farm Co. #1) has since been converted to an above-zone monitoring well to conduct monitoring above the confining zone.

This section provides a narrative document with associated schematics and data summary tables that describe how ExxonMobil constructed the injection wells to meet the goals of 40 CFR 146.86. The engineering design is based on the collection of as much site-specific data as possible, particularly from the stratigraphic well, before submitting the Class VI Permit Application. This level of effort was undertaken to facilitate the permit modification process, between conducting the pre-construction activities required at 40 CFR 146.82(a) and the pre-operation phase activities required at 40 CFR 146.82(c).

Objectives

ExxonMobil developed the engineering design, pre-operational testing plan, and operating strategy for the injection wells to meet the following objectives:

- The injection well construction design, material specifications, and construction were compatible with the composition of the CO_2 stream over the duration of the Project to reduce the potential for endangerment of USDWs [40 CFR 146.82(a)(11),(12); 146.86].
- The injection wells underwent logging and testing to assess injection well and formation performance and update the operating strategy as necessary before injection of CO_2 [40 CFR 146.82(a)(8); 146.87].
- The injection well operating strategy provides continuous injection and annulus monitoring systems for each injection well to control injection pressure and trigger automatic shut-off devices and safety valves for CO_2 injection, consistent with safe operating procedures [40 CFR 146.82(a)(7),(9),(10); 146.88(e)].

Engineering Design

The engineering design parameters for the three injection wells were based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. In addition, the engineering design included recompletion of each injection well to target-specific injection intervals to achieve the target CO_2 storage amount.

ExxonMobil plans to inject a maximum volume of 5 MMta for all three injection wells, which is an approximate rate of 264 million standard cubic feet per day at standard conditions. The tubing design, including size, weight, grade, and metallurgy was based on the properties of the injectate, rate of injection, and injection pressures determined by the detailed reservoir modeling.

The casing, cement, tubing, packer, continuous monitoring devices, and wellhead equipment were selected and designed to withstand the corrosive environment to which the materials and equipment will be exposed. Each was selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be subjected in the subsurface.

The following discussion presents the engineering design basis for the well materials including casing, tubing, and cement. Well design schematics and locations are included in Appendix D.1, which illustrate the well materials, design layout, and the locations of the packer and perforation intervals as well as the well location at the Project site.

The injection wells have been permitted for drilling through the RRC. A summary of the permitted well names and American Petroleum Institute (API) numbers is as follows:

Injection Well Information:

Well Name and Number	Labelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)
County	Jefferson
Location (RR D, S, A)	Railroad District 3, Section 42, Abstract 874
Latitude / Longitude (NAD83)	29.999678 / -94.285108
API	4224532913

The three injection wells were drilled and completed utilizing the strategy and procedures outlined in this plan. A material selection assessment was used for identifying adquate metallurgy and cement use for each injection well and can be found in Appendix D.4. Applicable and required permits and notifications were submitted to the RRC and EPA. The wells were drilled and tested as described in the pre-operational testing plan described in Section 4.4.

Overview of Injection Well Perforation Strategy

Each injection well was completed with a single completion string and assembly consisting of injection packer, nipple profile, safety injection valve, pressure/temperature gauges, and tubing. Upon issuance of authorization to inject, injection will start based on the intervals and injection schedules referenced below in Table 4-1 through 4-3. Once the target injection volume of CO2 is attained, that injection interval will be plugged back to isolate that interval from subsequent injection intervals shown on Figure 3-9. The next injection interval will then be completed and accessed through additional perforations to establish communication with the reservoir. CO2 will continue into that new injection interval until the target CO2 storage amount has been achieved for that interval. Tables 4-1 and 4-3 summarize the injection sequencing strategy for each injection well. The perforation depths provided in Tables 4-1 to 4-3 are based on the current geologic model described in Site Characterization (Section 2).

Table 4-1: Injection Sequencing Strategy for Injection Well No. 01

Stage	Sand Interval	Top Perf TVDSS (ft)	Bottom Perf TVDSS (ft)	Gross Thickness (ft)	Net Reservoir (ft)	Duration (years)
1	Upper Frio Sand	7,441	8,084	643	353	2.00
2	Upper Frio Sand	7,163	7,348	185	185	2.00

3	Upper Frio Sand	6,938	7,122	185	164	2.00
4	Fleming Sand 3	5,561	5,922	361	120	2.00
5	Fleming Sand 3	5,131	5,492	361	223	2.00
6	Fleming Sand 2	4,187	4,766	579	186	2.00
7	Fleming Sand 1	3,472	3,932	460	293	1.00
TVDSS = True Vertical Depth Subsea						

Production Casing Design and Completion

The production casing used a combination of 9-5/8-inch (in.) L-80, 13Cr-80, and 25Cr-125. In accordance with the June 25, 2024 guidance provided by EPA regarding Class VI Well Construction, 25Cr was utilized and installed across the entirety of the permitted upper confining zone. Additionally, 25Cr was installed at intra-permitted injection zone shale boundaries which correspond to notional packer placement depths and provide further redundancy. 13Cr was utilized across all perforated intervals.

The well design allowed for monitoring of each casing and tubing annulus for wellbore and mechanical integrity parameters. Appendices D.1 provide the wellbore designs and completion configurations for Injection Wells No. 01, No. 02, and No. 03, respectively, along with the certified well-location plats.

The production casing, or long-string casing, was the final, permanently cemented string of casing to be installed in each well. The production casing was run from the surface to total depth (TD) and cemented back to the surface. The key design criteria for the long string included the use of:

- 25Cr material used across the entirety of the permitted upper confining zone. Additionally, 25Cr was installed at intra-permitted injection zone shale boundaries.
- 13Cr material from the base of the permitted upper confining zone through the Fleming Sand perforation intervals and again across the Frio Sand perforation intervals
- Fiber optic line along the exterior of the production casing, terminating 50 ft into the Anahuac Shale
- CO2-compatible cement systems from 300 ft above the permitted upper confining zone across the entirety of the permitted upper confining zone to TD.

To reduce the potential for CO2 migration out of the injection interval, CO2-compatible cement was run from TD to at least 300 ft above the permitted upper confining zone, to provide a suitable barrier across the upper composite confining zone (UCCZ). By using CO2-compatible material, the cement is protected from carbonic acid, maintaining integrity throughout the life of the Project.

Throughout the life of each well, the Project will have a continual temperature monitoring system in place. The system is designed to measure and record downhole temperatures, as discussed in Section 5 – Testing and Monitoring Plan. Monitoring systems include a fiber optic cable with distributed temperature sensing outside of the 9-5/8 in. production casing. The fiber optic cable was installed at the top of the Anahuac Shale and cemented into place when the 9-5/8 in. casing-cementing job was performed.

The engineering and design parameters for the production casing are summarized in Tables 4-4 and 4-5. These depths are based on final logging of the injection wells.

Table 4-4: Production Casing Specifications

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft TVD KB) Well No. 01
9-5/8-in. L-80	9.625	8.681	8.525	47	6,870	4,760	1,086	0'–3,002'
9-5/8-in. 13Cr-80	9.625	8.681	8.525	47	6,870	4,760	1,086	3,552'–3,976', 4,233'–4,885', 5,066'–5,311'
9-5/8-in. 13Cr-80	9.625	8.535	8.379	53.5	7,930	6,620	1,244	5,311'–6,338' 6,555'–8,533'
9-5/8 in.25Cr-125	9.625	8.535	8.379	53.5	12,740	8,440	1,943	3,002'–3,552', 3,976'–4,233', 4,885'–5,066', 6,338'–6,555'
9-5/8-in. L-80	9.625	8.535	8.379	53.5	7,930	6,620	1,244	8,533'–8,654'
ft = feet; ID = inner diameter; KB = Kelly Bushing; kips = 1,000 pound-force; lb = pound; OD = outer diameter; psi = pounds per square inch								

Table 4-5: Production Casing Design Calculations

- 9-5/8-in. Casing
- 9-5/8-in. 47 ppf L80, Semi-Premium, 0 - 3,049 ft
- 9-5/8-in. 53.5 ppf 25Cr-125, Premium, 3,049 ft – 3,597 ft, 4,129 ft – 4,347 ft, 4,966 ft – 5,147 ft, 6,428 ft – 6,647 ft
- 9-5/8-in. 47 ppf L80-13Cr, Premium, 3,597 – 4,129 ft, 4,347 ft – 4,966 ft, 5,147 ft – 6,428 ft, 6,647 ft – 8,610 ft
- 9-5/8-in. 53.5 ppf L80, Premium, 8,610 ft – 8,731 ft

9-5/8-in.	Load Type - Working Stress Design	Load (lb) or (psi)	Depth (ft)	Min SF	Depth (ft)
Burst	Tubing Leak – 2,750 psi Injection Pressure, 6.1 ppg packer fluid	2,750 (psi)	0	2.5	0
	Pressure Test – 4,000 psi with 8.5 ppg FW	4,000 (psi)	0	1.5	8,473

	Casing Frac – 2,533 psi with 7.5 ppg Inj. Fluid	2,533 (psi)	0	2.5	8,473
Tension	Green Cement – 4,000 psi with 10.0 ppg NADF	447 (kips)	0	1.8	0
	Running With Overpull – 100 kips	459 (kips)	0	2.4	0
	Buckling Check – cement to surface, injection temperature	0	0	5.2	0
Collapse	Evacuated Collapse – Full evacuation	4,531 (psi)	8,731	1.0	8,610
kips = 1,000 pound-force; lb = pound; NADF = non-aqueous drilling fluid; ppf = pounds per foot; ppg = pounds per gallon; psi = pounds per square inch; SF = safety factor Note: maximum anticipated surface pressure = 5,000 psi (production packer setting pressure)					

Tables 4-6 to 4-8 provide the production casing cement volume calculations for each injection well.

Table 4-6: Production Casing Cement Volume Calculations for Injection Well No. 01

Section	Footage (ft)	Capacity (ft^3/ft)	Excess (%)	Cement Volume (ft^3)
Surface/Production Casing Annulus	2,203’	0.335	10	812
Open Hole/Casing Annulus	6,451’	0.313	20	3,631
Shoe Track	43’	0.397	0	17
Total Volume, ft^3 (bbl)				3,252 (579)
Actual Volume Pumped, bbl (sacks)				682 (2035)
bbl = barrel; ft^3 = cubic feet				

Centralizer placement for the 9-5/8-in. production casing was designed to accommodate the installation of the fiber optic cable and to promote a continuous, uniform column of cement throughout the production casing annulus achieving greater than 80% displacement efficiency. Clamp centralizers and eccentric centralizers were used to reduce the potential for damage to the fiber optic cable. The placement of centralizers through the production casing is shown in Table 4-9.

Table 4-9: Production Casing Centralizer Program

Centralizer Type	Centralizer Frequency	Injection Well No. 01	
		Depth (ft)	Qty
Centralized cross coupling protector	Every other joint	0’–2,065’	25
Cast coupling centralizer	Every other joint	0’–2,065’	25
Cast coupling centralizer	One every joint	2,188’–6,101’	79

Cable detection clamp	One every joint	3,552'–3,938' 4,234'–4,846', 5,066'–6,101'	48
Centralizers	One every joint	6,101' – 8,652'	63

Injection Tubing Design and Completion

The 7-in. injection tubing size and material were selected for use in the Project wells based on injection volumes, rates, and injectate composition. Consistent with the design approach used for the casing strings, the injectate and the potential for a corrosive environment are important considerations when selecting the metallurgy of the tubing. The design offers protection from the potential corrosive environment of the injectate stream and potential for influx of reservoir brine.

The production tubing is 7-in. 13Cr-80, installed with an injection packer. This design uses 13Cr material or its equivalent in all sections where the CO_2 will contact the tubulars. A tubing design analysis was conducted that considered calculated pipe-friction losses, exit velocities, and compression requirements.

Table 4-10: Composition of the Most-Concentrated Constituents in Injectate

Constituents	Mole Percent
Carbon dioxide	>97%
Hydrogen	<1%
Methane	<3%

The input injection parameters from the model are shown in Table 4-11 and 4-12. The calculated injection parameters are shown in Tables 4-13 through Table 4-15 for Injection Wells No. 01 to No. 03, respectively.

Table 4-11: CO_2 Standard Conditions

Temperature °F	Pressure psia	Density lbm/ft^3	Enthalpy Btu/lbm	Entropy Btu/lbm-°R
CBI [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
°F = degrees Fahrenheit; °R = Rankine; Btu = British thermal unit; ft^3 = cubic feet; lbm = pounds mass; psia = pounds per square inch absolute				

Table 4-12: Input Injection Parameters for Injection Wells No. 01

Parameter	Injection Well No. 01
Max Injection Rate (MMta)	1.67
CBI [redacted]	[redacted]
Injection Duration (years)	13
7-in. Tubing Inner Diameter (in.)	6.276
7-in. Tubing Initial Setting Depth (ft)	7,421'
Wellhead Temperature °F	80

Table 4-13: Modeled Injection Rates and Pressures for Injection Well No. 01

Stage	Year After Startup	Max. Rate (MMta)	Avg. Rate (MMta)	Max. BHP (psi)	Avg. BHP (psi)
1	0.00	1.67	1.67	3,720	3,600
2	2.00	1.67	1.67	3,543	3,462
3	4.00	1.67	1.67	3,544	3,465
4	6.00	1.43	1.43	2,825	2,667
5	8.00	1.43	1.43	2,627	2,563
6	10.00	1.26	1.26	2,140	2,100
7	12.00	1.1	1.1	1,777	1,731
psi = pounds per square inch					

13Cr material was used for the tubing strings. The tubing was installed using premium connections. A single pressure and temperature gauge was installed above the packer to monitor CO2 injection through the tubing. Tables 4-16 and 4-17 provide the tubing design parameters.

Table 4-16: Tubing Specifications

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft)
								Injection Well No.01
7-in. L80- 13Cr	7.000	6.276	6.151	26.0	7,240	5,410	604	0–7,421’
7” 25Cr-125	7.000	6.276	6.151	26.0	11,640	6,450	944	-
ID = inner diameter; kips = thousand pounds; lb = pound; OD = outer diameter; psi = pounds per square inch								

Table 4-17: Engineering Design Calculations for Tubing

Production tubing 13Cr, VAM21					
7-in.	Load Type – Working Stress Design	Load (kips) or (psi)	Depth (ft)	Min SF	Depth (ft)
Burst	Tubing	4,750 (psi)	7,500	1.31	7,500
	Injection test	2,500 (psi)	7,500	2.50	7,500
Tension	Buoyed weight + 100kips overpull	275 (kips)	0	2.19	0
	1.67 MMta per well	153 (kips)	0	3.62	0
Collapse	Long shut-in	950* (psi)	7,500	2.03	7,500
	Tubing evacuation	1,050** (psi)	7,500	1.67	7,500
kips = 1,000 pound-force; lb = pound; psi = pounds per square inch; SF = safety factor Note: maximum anticipated surface pressure = 5,000 psi (production packer setting pressure) *With 2,250 psi on the A-Annulus **With 1,800 reservoir pressure (end of life BHP) with .01 psi/ft gas gradient to surface and 2,250 on A- Annulus					

Surface Conductor Pipe Design and Completion

The unconsolidated nature of the sediments in the upper subsurface soil required the installation of a conductor pipe to establish and maintain borehole integrity. A cellar was installed, a 26-in. hole was drilled to depth, and a 20-in. casing was then run and cemented conventionally. A 17 1/2-in. bit was used to drill the next section of the well through the conductor pipe.

Surface Casing Design and Completion

The surface hole was drilled to below the USDW with a 17 1/2-in. bit, with surface casing set at approximately 2,200 ft for each of the injection wells. A string of 13 3/8-in. casing was run and cemented with the casing centered in the open hole with centralizers. The generalized surface casing centralizer placement for the injection wells is provided in Table 4-18.

Table 4-18: Summary of Design for Surface Casing Centralizer

Centralizer Type	Centralizer Frequency	Depth (ft)	Quantity
Bow Spring	One every joint	2,118'–2,203'	2
Bow Spring	One every third joint	126'–2,118'	16
		Total:	18

A summary of surface casing design parameters is presented in Tables 4-19 through 4-21. The engineering calculations for the three injection wells are based on the wellbore conditions and maximum setting depth for the surface casing at Injection Well No. 02.

Table 4-19: Summary of Design for Surface Casing Completion for Injection Wells No. 01

Section	OD (in.)	ID (in.)	Drift (in.)	Weight (lb/ft)	Burst (psi)	Collapse (psi)	Tensile (kips)	Intervals (ft) Injection Well No. 01
13-3/8-in. J-55	13.375	12.415	12.259	68.0	3,450	1,950	1,069	0'–2,203'
ID = inner diameter; kips = thousand pounds; lb = pound; OD = outer diameter; psi = pounds per square inch								

Table 4-20: Surface Casing Design Calculations for Injection Wells

13-3/8-in. Casing 13-3/8-in. 68 ppf J-55 BTC, 0 - 2,250 ft					
13-3/8-in.	Load Type – Working Stress Design	Load (lb) or (psi)	Depth (ft)	Min SF	Depth (ft)
Burst	Kick	1,574 (psi)	0	2.2	0
	Pressure Test – 2,750 psi with 10 ppg OBM	2,926 (psi)	2,250	1.2	2,250
Tension	Green Cement – 2,750 psi with 10 ppg OBM	422 (kips)	0	1.4	0
	Running With Overpull – 100 kips	231 (kips)	0	4.6	0
	Buckling Check – cement to surface, max MW 11.0 ppg	86 (kips)	0	12.4	0
Collapse	Cementing Collapse	297 (psi)	2,215	6.5	2,215

	Future Drilling – minimum MW 8.5 ppg	471 (psi)	2,250	4.1	2,250
BTC = buttress-thread and coupled; kips = thousand pounds; lb = pound; MW = mud weight; OBM = Oil Based Mud; ppf = pounds per foot; ppg = pounds per gallon; psi = pounds per square inch; SF = safety factor					

Table 4-21: Surface Casing Cement Volume Calculations for Injection Wells

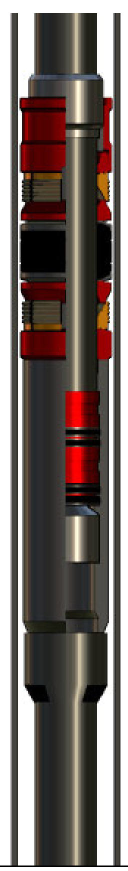
Section	Barrels	Sacks
Injection Well No. 01	424	1575

Injection Tubing Packer Design and Completion

A wireline-set injection packer was installed with the 7-in. injection tubing. The hydrogenated nitrile rubber (HNBR) element and flow-wetted material components were specifically selected for compatibility with the expected composition of the CO2 injection stream and well fluids in the wellbore. Prior to setting the packer, the tubing annulus was filled with a non-corrosive fluid.

Figure 4-1 provides a schematic illustration of a suitable packer design and completion for the Project.

Figure 4-1: Schematic for the Injection Packer Design Tubing

<table>
<tr><td colspan="3">Injection Packer</td></tr>
<tr><td rowspan="6"></td><td>Size</td><td>13Cr Halliburton Perma series or suitable equivalent 9-5/8” x 5-1/2”</td></tr>
<tr><td>Setting</td><td>Wireline set</td></tr>
<tr><td>Sealbore extension</td><td>6” x 10’ 13Cr</td></tr>
<tr><td>Differential pressure</td><td>7,500psi</td></tr>
<tr><td>Min ID (with sealbore)</td><td>4.67”</td></tr>
<tr><td>Temperature</td><td>40-350 F</td></tr>
</table>

Safety and Continuous Monitoring Device Design and Completion

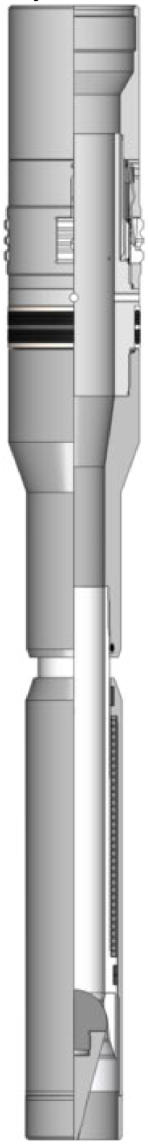
The following safety and continuous monitoring devices were designed for installation in the injection wells.

Safety Injection Valve

A 5.963-in. landing nipple profile was installed above the packer in each 7-in. tubing string to set a safety/injection valve in the injection wells. In the event that injection is interrupted, the injection valve will limit the potential for fluid backflow into the injection tubing string and will keep the reservoir pressurized until equilibrium is achieved. When the safety injection valve is closed, it will maintain the injected CO_2 below the valve in a supercritical state.

The safety injection valve was run on wireline and set in a no-go nipple profile located above the injection packer. The valve was designed to the API 14A standard. The operation of the valve consists of a variable orifice that actively adjusts the instantaneous injection flow to maintain a consistent low-back pressure without a flapper or flow tube. The valve will be retrieved each time an intervention is required to isolate an injection zone or make new perforations. Figure 4-2 provides a schematic and specifications for the safety injection valve..

Figure 4-2: Safety Injection Valve



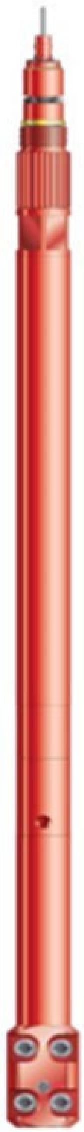
Tool Description	
Valve Description	5.500 Inject**GARD™** Safety Valve with 5.963" RPT Lock
Technical Specifications	
Polished Bore	5.963 inch
Lock Mandrel Type	Halliburton RPT
Overall Length	52 inch
Valve Max OD	4.375 inch
Valve Min ID	2.790 inch
Spacer Max OD	6.025 inch
Spacer Min ID	2.790 inch
Flow Area	6.11 sq. inch
Flow Wetted Materials	Inconel 718, Inconel 925, 6% TC, Boron
Seal Material	Hydrogenated Nitrile Rubber, PEEK
Temperature Rating	-110°F to 275°F
Working Pressure Rating	10,000 psi
Maximum Injection Rate	2.0 MTPA Liquid Carbon Dioxide
QMS System	API Q1/ISO 9001:2015 (E)
Industry Standards	API-14A, Validation Grade V3 SSISV

Downhole Pressure and Temperature Gauge Design and Completion

A single pressure and temperature gauge was run above the injection packer in each injection well to provide real-time bottomhole monitoring data. The gauge was ported to the interior of the injection tubing and pressure and temperature measurements will be fed to the surface using the installed tubing encapsulated conductor line. Figure 4-3 provides specifications of the downhole pressure and temperature gauge.

Figure 4-3: Downhole Pressure and Temperature Gauge

GAUGE OPSIS VENDOR PN
WDB206-10-150



Design Specifications

SAP Part Number: 102815210
Legacy Part Number: OPS34S1015000

Name	Value
GAUGE SETUP	SINGLE
CALIBRATION PRESSURE RANGE	200-10000 PSI
CALIBRATION TEMPERATURE RANGE	25-150 DEG. C
SERVICE	H2S/CO2
SERVICE REMARKS	H2S AND/OR CO2 SERVICE BASED ON CUSTOMER DEFINED, WELL SPECIFIC CONDITIONS. APPLICATIONS MUST BE REVIEWED FOR SPECIFIC ENVIRONMENTAL COMPATIBILITY.
MATERIAL	MP-35-N
PRESSURE READING ACCURACY	0.015 % FULL SCALE
ACHIEVABLE PRESSURE RESOLUTION	LESS THAN 0.006 PSI/SEC
PRESSURE DRIFT AT MAX TEMP AND PRESSURE	0.02% FULL SCALE/YEAR
TEMPERATURE ACCURACY	0.5 DEG. C
ACHIEVABLE TEMPERATURE RESOLUTION	LESS THAN 0.005 DEG. C/SEC
MAXIMUM OD	0.765 inch
MINIMUM STORAGE TEMPERATURE	-40
MINIMUM OPERATING TEMPERATURE	-20 Deg. C
MAXIMUM STORAGE TEMPERATURE	65 Deg. C
MAXIMUM OPERATING RANDOM VIBRATION	10Grms
MAXIMUM OPERATING SHOCK	500g 2MS 1/2 SINE 6-AXIS
MAXIMUM SAMPLING RATE	0.24 second
OPERATING VOLTAGE	18:60 volt DC
MAXIMUM ACTIVE CURRENT CONSUMPTION	0.02 ampere
COMMUNICATION PROTOCOL	MODBUS RTU
GAUGE SIZE	0.75 inch
LENGTH	13.742 inch
APPROXIMATE PART WEIGHT	2.0 pound
CONNECTION TYPE	CABLE TERM
OUTSIDE DIAMETER	0.765 inch

Fiber Optic Design and Completion

Fiber optic cable was run on the production casing string in each injection well to monitor temperature.

Wellhead Equipment Design and Completion

The wellhead was designed to manage working pressures and provide a high degree of mechanical integrity for the injection well. The wellhead equipment was manufactured with stainless-steel components across the hanger, casing spool, and tree assembly and Inconel cladding as described in Figure 4-4 below. The wellheads were configured as illustrated in Figure 4-4.

Figure 4-4: Typical Wellhead Configuration for Injection Wells

CBI

[redacted]

Well Drilling and Completion Design

The drilling and completion design for each injection well is described in the following sections. Appendix D.1 provides the final well design and completions details.

Drilling and Completion Design for Injection Well No. 01

CBI [redacted]

CBI [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

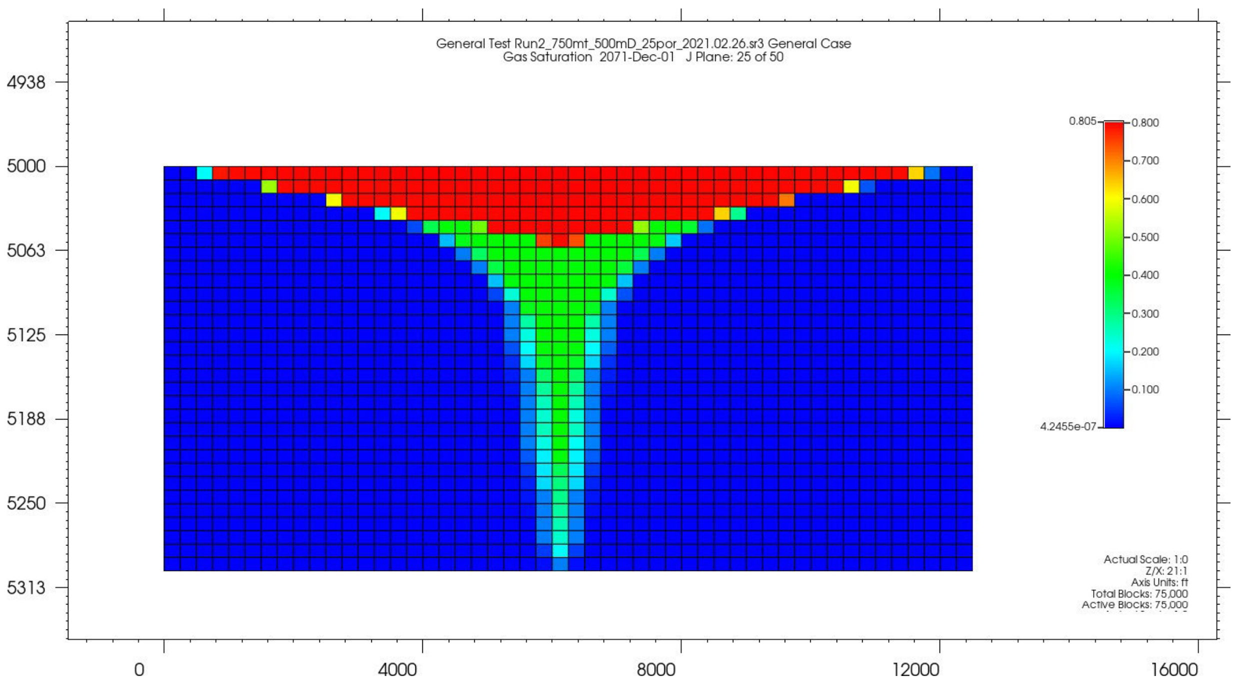
CBI [redacted]

Injection Well Completion Stage and Injection Interval

The density difference between injected CO2 and connate brine, in addition to the relatively high vertical permeability in the Fleming and Upper Frio sands, allows the CO2 to migrate vertically to the top of each discrete injection interval and laterally under the confining layer (or baffle) that exists at the top of that injection interval.

The result is a significant "mushroom cap" effect wherein gravity override of the less dense CO2 plume occurs due to gravity segregation over distance, with the top of the mushroom expanding outwardly from the injection well (Figure 4-5). Additional details regarding the predicted plume movement and pressurization of the injection zone are presented in Section 3 – Area of Review and Corrective Action Plan.

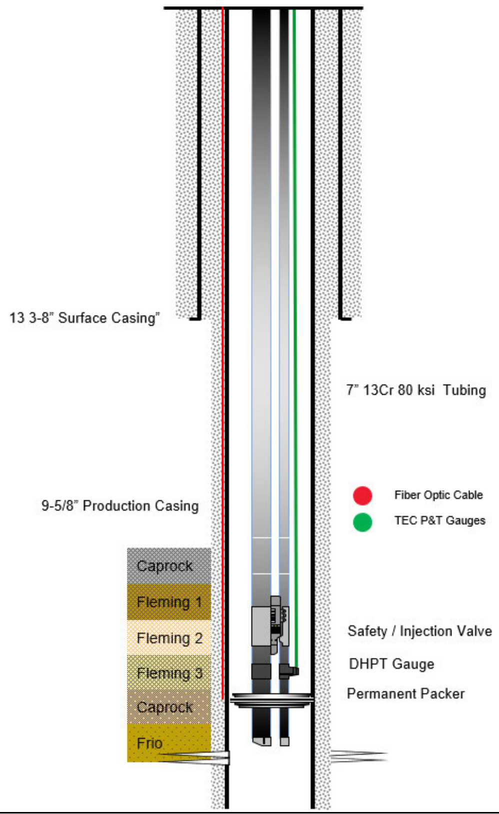
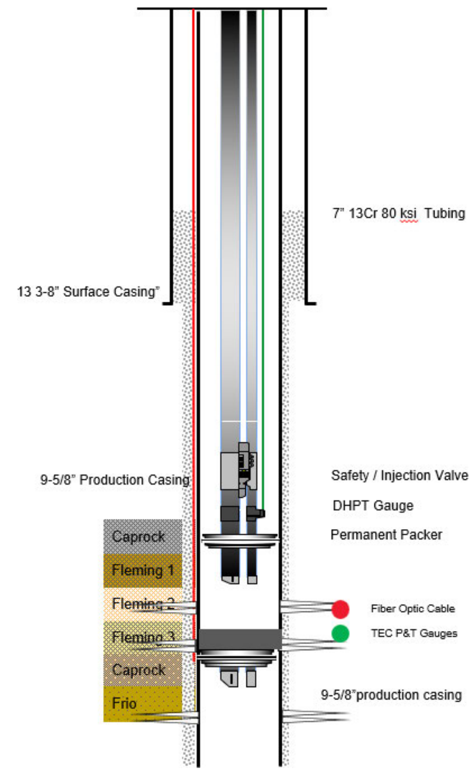
Figure 4-5: Typical Plume Profile in High Permeability Formations



To maximize the use of pore space and minimize the cone-of-influence pressure that is created due to injection, discrete injection stages must be completed over limited periods of the total operational life of the Project. Reservoir management is important for sequestration operations in thick, high permeability, poorly consolidated sand formations. Through modeling of injection in the reservoir, predictions of the CO2 plume development were generated based on this well- specific completion strategy.

As mentioned above, Figure 4-6 illustrates the sequencing plan for completing the four target injection stages within the injection interval of the injection zone. At the end of this initial injection period and each subsequent injection period, workover operations will be executed to recomplete into a new stage. A plug will be set to isolate each injection stage that has met the CO2 storage target and the 9-5/8 in. production string will be perforated to access the next injection stage. This process will be repeated until the end of the Project operating life. Figure 4- 6 depicts this process in a general form.

Figure 4-6: Operational Completion Strategy for Injection Wells

From Upper Frio	To Fleming Sand
	

Each discrete injection stage was selected to maximize the use of the pore space and collectively maximize the usage of the acreage position for CO2 sequestration. A summary of the planned injection stages and duration by sand unit are listed in Tables 4-22 through 4-35. These stages are based on the current geologic model and stratigraphic well results.

Table 4-22: Injection Intervals for Injection Well No. 01

Completion Stage	Completion Years after Startup	Injection Duration (years)	Top Depth TVDSS (ft)	Bottom Depth TVDSS (ft)	Net Reservoir (ft)
Upper Frio Sand	0.00	2.00	7,441	8,084	353
Upper Frio Sand	2.00	2.00	7,163	7,348	185
Upper Frio Sand	4.00	2.00	6,938	7,122	164
Fleming Sand 3	6.00	2.00	5,561	5,922	120
Fleming Sand 3	8.00	2.00	5,131	5,492	223

Fleming Sand 2	10.00	2.00	4,187	4,766	186
Fleming Sand 1	12.00	1.00	3,472	3,932	293
TVDSS = True Vertical Depth Subsea					

Pre-Operational Testing Plan

The scope of the pre-operational testing plan included geophysical and core data collection in the stratigraphic well, fluid sampling at target intervals, and pressure testing to assess the injection intervals. The Testing and Monitoring Plan (Section 5 – Testing and Monitoring Plan) provides the data collection activities for the pre-operational phase and the operational phase of the Project. A summary of that discussion is provided below for ease of review, with reference to the complete discussion in Section 5 for the pre-operational testing plan.

Tests During Well Drilling and Construction

A variety of geophysical well logs were collected during the construction of the stratigraphic well to verify and evaluate further the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in the relevant geologic formations. Data collected from the stratigraphic well was also used to appropriately construct the injection wells and provide data to verify the design for mechanical integrity purposes.

The drilling procedure in Appendix D.2 discusses the detailed coring procedures for the stratigraphic well (Bead Farm Co. #1). The coring depths, formations, and footages for full core samples are provided in Table 4-25. The cores taken from the stratigraphic well were near the injection wells and represent the properties of the injection and confining zones near the injection wells. Data acquisition from the stratigraphic well included sufficient and representative information on the injection and confining zones porosities, permeabilities, petrologies, and mineralogies.

Table 4-25: Summary of Full Core Sample Depths from Stratigraphic and Injection Well

Interval	Bead Farm Co #1		Labelle Properties Ltd. #1		Bead Farm Co #2		Bead Farm #3	
	(ft TVD)	Footage (ft)	(ft TVD)	Footage (ft)	(ft TVD)	Footage (ft)	(ft TVD)	Footage (ft)
Fleming Sand Seal Complex	3,092	110	-	-	3,120	31	3,333	60
Fleming Sand 1	-	-	3,565	28	-	-	3,503	68
Fleming Sand Shale 2	4,060	60	-	-	-	-		-

Fleming Sand 2	4,456	32	-	-	4,350	53	-	-
Fleming Sand 3	5,186	31	-	-	-	-	-	-
Anahuac Seal	6,266	36	-	-	-	-	-	-
Upper Frio	7,255	54	7,481	56	7,586	60	7,770	44

Injection and Confining Zone Core Sampling

During the drilling and completion of the injection wells, a subset of the stratigraphic well's logging and coring data collection plan were used to verify certain key parameters for injection well performance and AoR modeling. The following geophysical logs were run for each injection well. The open-hole logging plan is detailed in Table 4-26. The cased-hole logging plan is detailed in Table 4-27.

Table 4-26: Open-Hole Logging Plan for Injection Wells No. 01

Section	Open-Hole Logs	Injection Well No. 01 ft TVD KB
17-1/2 in. hole	• Gamma Ray • Resistivity • Spontaneous Potential • Caliper	0–2,203
12-1/4 in. hole	• Gamma Ray • Resistivity • Density • Neutron • Magnetic Resonance • Dipole Sonic • Borehole Imaging • Caliper • Formation Pressure • Fluid Samples	2,203–8,654

Table 4-27: Cased-Hole Logging Plan for Injection Wells No. 01

Section	Cased-Hole Logs	Injection Well No.01ft TVD KB
13-3/8 in. surface casing	• CBL, VDL, Temp,	0–2,203
9-5/8 in. production casing	• CBL, VDL, Temp, • Ultrasonic Casing Inspection	0–8,586
7-in. production tubing and 9-5/8 in.	• Thru-Tubing Casing Inspection • Pulse Neutron / OA	0–8,535

Injection Zone Characterization

The injection zone was characterized in detail using the data acquired in the stratigraphic well (Bead Farm Co. #1) and outlined in Appendix D.2. The location of the stratigraphic well relative to the injection wells is provided on Figure 5-3. ExxonMobil collected characterization data for each injection interval of the injection wells including formation fluid temperature, pH, specific conductivity and formation pressure. All target injection formations are 100% brine saturated.

Fracture Pressure, Fluid Characteristics, and Downhole Conditions

ExxonMobil characterized the formation fluids in the injection zone using samples collected from the stratigraphic well. ExxonMobil used these data to evaluate the compatibility of the injectate with the formation fluids in the injection zone. These groundwater samples that were collected during the pre-operation phase of the Project will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Project. In general, the baseline data established include pressure, temperature, fluid, and physical characteristics present in the injection intervals and above the UCCZ from a single sample event at the stratigraphic well and a routine sampling frequency for the USDW monitoring wells.

The sampling and analysis plan for the water sample collected above the UCCZ at the stratigraphic well is specified in Table 4-28. The USDW monitoring wells were drilled and monitored to provide a representative baseline of geochemical concentrations and pressure conditions in the AoR and surrounding area as described in Section 5 – Testing and Monitoring Plan. The analyses of geochemical and water quality parameters for the groundwater samples from the USDW monitoring wells are specified in Section 5. Similarly, groundwater characterization between the lowest most USDW and the top of the UCCZ was tested and sampled inside the limits of the AoR to establish a representative baseline of geochemical and pressure conditions of the monitoring zone in the local Project area.

Table 4-28: Sampling and Analysis Plan for UCCZ Water Sample Collected from Stratigraphic Well

Parameter/Analyze	Analytical Method
Total dissolved solids, alkalinity, electrical conductivity, temperature, pH	Standard lab analyses
Gas composition (CO_2, CH_4, O_2, N_2)	Gas chromatography
Dissolved cations (i.e., Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn)	Ion chromatography
Dissolved anions (HCO_3, $B(OH)_4$, Br, CO_3, Cl, F, I, NO_3, NO_2, PO_4, SO_4, S)	Ion chromatography
$B(OH)_4$ = Tetrahydroxyborate; Ba = Barium; Br = Bromide; Ca = Calcium; Cd = Cadmium; CH_4 = Methane; Cl = Chloride; CO_2 = Carbon dioxide; CO_3 = Carbonate; Co = Cobalt; Cr = Chromium; Cu = Copper; F = Fluoride; Fe = Iron; HCO_3 = Bicarbonate; I = Iodide; K = Potassium; Li = Lithium; Mg = Magnesium; Mn = Manganese; Mo = Molybdenum; N_2 = Nitrogen; Na = Sodium; Ni = Nickel; NO_2 = Nitrite; NO_3 = Nitrate; O_2 = Oxygen; P = Phosphorus; Pb = Lead; PO_4 = Phosphate; S = Sulfur; Si =Silicon; SO_4 = Sulfate; Sr = Strontium; V = Vanadium; Zn = Zinc.	

The groundwater samples were analyzed in the field for certain physical parameters including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity. Laboratory-based analyses included total dissolved solids, concentrations of cations, anions, CO_2, and methane. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

Injection and Confining Zone Formation Testing

ExxonMobil collected pre-operational formation tests and data logging from the stratigraphic well to provide needed data on the geologic and hydrogeologic properties of subsurface formations. A step-rate test and a pressure fall-off test were performed in three intervals (Upper Frio, Fleming 3, and Fleming 2) at the stratigraphic test well . As an example, Tables 4-29 and 4-30 provide the step-rate injection test and pressure fall-off test parameters for the Fleming 2 interval. A discussion of all injectivity tests performed at the stratigraphic test well are provided in Appendix B.3.

The final rates and durations for each test are made during the operation based on real-time downhole pressure data, ensuring that sufficient time is allowed for downhole stabilization at each rate. No minimum hold time is explicitly prescribed, as it depends on individual well performance. The target injection intervals were found to be exceptionally productive and exhibited very low pressure response to the injection rate. Therefore, it was necessary to ramp up quickly to build the amplitude of pressure disturbance needed to monitor and analyze the performance.

Table 4-29: Step-Rate Injection Test in Fleming 2 at the Stratigraphic Well

CBI [redacted]

CB [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBI [redacted]					

Table 4-30: Pressure Fall-Off Test in Fleming 2 at the Stratigraphic Well

CBI [redacted]		[redacted]	[redacted]		
	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					

Pressure transient well testing (e.g., a pressure fall-off test) was completed in the stratigraphic well and in each of the injection wells as a part of completion activities. These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. The following injection well fall-off pressure test procedures were completed:

- A non-hazardous test fluid was completed during the injection test.
- Injection Well Fall-Off Pressure Test:
  - The purpose of this test is to evaluate the injectivity index, skin, and permeability-thickness of the injection intervals.
  - For each injection zone, an injectivity test was performed.
  - The wells were shut-in and pressure fall-off was recorded with downhole gauges over sufficient time for proper analysis.

Quality Assurance Surveillance Plan

ExxonMobil developed the Quality Assurance Surveillance Plan (QASP) in Appendix E in this application as a supplement to the testing and monitoring requirements of this section as well as Section 5 – Testing and Monitoring Plan and Section 7 – Post-Inject Site Care and Site Closure Plan. The goal of the QASP is to provide reliable data to verify that the Project is operating as permitted without endangerment to USDWs. The QASP provides a verifiable set of standards and controls that include the technologies, methodologies, frequencies, sample quality assurance, and procedures to demonstrate the collection data activities will provide accurate and reliable information about the Project operations. The QASP is unique to the Project, informed by site-specific details, monitoring technologies selected, and will be updated as the Project evolves in concert with the Testing and Monitoring Plan.

Injection Well Operating Strategy

Injection Rate and Pressure

Table 4-31 provides the proposed operations for the injection wells including injection rate and pressure by well. The maximum injection rates for the injection intervals of each well ranges from 0.73 to 1.67 MMta. The average injection rate range is from 0.73 to 1.67 MMta. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-31. Both the injection rates and pressures are within the operating window of the injection wells.

Table 4-31: Summary of Injection Parameters for Injection Wells No. 01

Stage	Stage	Parameter	Injection Well No. 01
1	Frio-1	Maximum Injection Zone Rate (MMta)	1.67
		Average Injection Zone Rate (MMta)	1.67
		Maximum Allowed BHP (psi)	4,620
		Maximum Modeled BHP (psi)	3,720
2	Frio-2	Maximum Injection Zone Rate (MMta)	1.67
		Average Injection Zone Rate (MMta)	1.67
		Maximum Allowed BHP (psi)	4,463
		Maximum Modeled BHP (psi)	3,543
3	Frio-3	Maximum Injection Zone Rate (MMta)	1.67
		Average Injection Zone Rate (MMta)	1.67
		Maximum Allowed BHP (psi)	4,323
		Maximum Modeled BHP (psi)	3,544

4	Fleming 3-1	Maximum Injection Zone Rate (MMta)	1.43
		Average Injection Zone Rate (MMta)	1.43
		Maximum Allowed BHP (psi)	3,417
		Maximum Modeled BHP (psi)	2,825
5	Fleming 3-2	Maximum Injection Zone Rate (MMta)	1.43
		Average Injection Zone Rate (MMta)	1.43
		Maximum Allowed BHP (psi)	3,154
		Maximum Modeled BHP (psi)	2,627
6	Fleming 2	Maximum Injection Zone Rate (MMta)	1.26
		Average Injection Zone Rate (MMta)	1.26
		Maximum Allowed BHP (psi)	2,577
		Maximum Modeled BHP (psi)	2,140
7	Fleming 1	Maximum Injection Zone Rate (MMta)	1.10
		Average Injection Zone Rate (MMta)	1.10
		Maximum Allowed BHP (psi)	2,107
		Maximum Modeled BHP (psi)	1,777

The proposed continuous monitoring and recording devices will demonstrate internal mechanical integrity [40 CFR 146.88(e)] and that the well is equipped with shutoffs and safety devices that are linked to final operating limits specified in the permit for each injection well. The anticipated bottomhole injection pressures and interval-specific pressure constraints are shown in Tables 4-32 through 4-34. The injection depths are based on the current geologic model and stratigraphic well results. The injection rate schedule presented in this Application is based on defined rate limitations without the modeled projections predicting sufficiently high reservoir pressures that result in maximum BHP constraining predicted well operations.

Table 4-32: Injection Pressures and Pressure Constraints by Injection Stage for Injection Well No. 01

Completion Stage	Completion Years after Startup	Top Depth BGL (ft)	CBI [redacted]	Fracture Pressure (psi)	Maximum Allowable BHP (psi)
Upper Frio Sand	0.00	7,440	CBI [redacted]	5,134	4,620
Upper Frio Sand	2.00	7,186	CBI [redacted]	4,958	4,463
Upper Frio Sand	4.00	6,961	CBI [redacted]	4,803	4,323
Fleming Sand 3	6.00	5,584	CBI [redacted]	3,797	3,417

Fleming Sand 3	8.00	5,154	CBI [redacted]	3,505	3,154
Fleming Sand 2	10.00	4,210	CBI [redacted]	2,863	2,577
Fleming Sand 1	12.00	3,495	CBI [redacted]	2,342	2,107
BGL = below ground level; ft = feet; psi = pounds per square inch					

CO2 Volume

ExxonMobil plans to inject approximately 53 million metric tonnes of CO2 over the life of the Project. It is projected that the CO2 will be injected and will remain in a supercritical state through the life of the Project. The Fleming and Upper Frio sands have relatively high porosity and high permeability. These reservoir properties and the lateral extent of the injection zone are projected to allow the system to store significant volumes of CO2 with limited reservoir pressure rise and to result in relatively rapid pressure fall-off upon shut-in. The CO2 volume was determined to meet the requirements of managing the threat of endangerment to USDW.

Annulus Pressure

The annulus pressure will be adjusted to be more than 100 psi above the wellhead injection pressure, with a maximum allowable pressure of 2,750 psi. The minimum annulus pressure is 500 psi, as reported in Section 5 – Testing and Monitoring Plan.

Well Stimulation Procedures

In the event it is necessary to achieved desired injectivity, ExxonMobil may stimulate the injection zone for the Rose CCS Project (Appendix D.3). Stimulation may be conducted if injection impairment is observed during the life of the well. Additional details on the stimulation plan can be found in Appendix D.3. Potential causes for injection reduction are:

- Formation damage (e.g., fines migration, scaling, debris in injection stream)
- Geochemical reactions due to fluid / reservoir incompatibility
- Salt precipitation due to in situ brine vaporization
- Reservoir compartmentalization or facies variation
- Shale swelling
- Others

ExxonMobil, will provide advance notice of the proposed stimulation to the UIC Program Director in writing at least 30 days prior to implementation in accordance with 40 CFR 146.91(d)(2). The detailed stimulation plan is provided in Appendix D and incorporates the following:

- Stimulation design to ensure the treatment will not interfere with containment
- Stimulation fluids detail (e.g., volumes, concentrations, additives)
- Stimulation fluid / well material compatibility analysis
- Well Integrity analysis (e.g., casing / tubing stress analysis)

- Stimulation procedure

The stimulation fluids will be an acid, most likely HCl, or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned in the paragraph above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Program Director should a stimulation become necessary:

1. Determine compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop stimulation plan based on the injection impairment cause
3. Provide work procedure and stimulation program to the UIC Program Director in writing at least 30-days prior to the planned date for start of the work (40 CFR 146.91(d)(2)).
4. Prepare wellsite and mobilize equipment
5. Shut-in and isolate the well from the CO2 injection system. Allow the pressures to stabilize
8. Rig up the stimulation equipment.
9. Prepare the well for stimulation.
10. Perform the stimulation treatment as per approved plan.
11. Flush the wellbore with treated water and prepare the well to return to normal operation
12. Rig down and return the well back to injection

CO2 Stream Characteristics

The CO2 stream chemical composition is described in Table 4-10. No solids are expected to be present in the CO2 stream and the composition is >97 mole percent CO2.

In general, unanticipated interactions among the CO2 injectate and the reservoir fluids are not expected that would act to reduce the permeability, porosity, or injectivity of CO2 into the injection intervals over the life of Project. Specific mineralogy and fluid testing were performed on core and fluid samples taken from the stratigraphic well to confirm these conditions prior to issuance of the Class VI permits. This included an assessment of the potential for mineral dissolution or precipitation within the Fleming and Upper Frio injection intervals that could potentially endanger USDWs. As outlined in this section, the current engineering design basis includes corrosion resistant well completion materials selected to provide a high degree of mechanical integrity under future conditions for the formation fluids and CO2 plume. See Section 6.2.5 for a summary of the proposed CO2 compatible cement.

Section 5 – Testing and Monitoring Plan provides a description of the analyses of the CO2 stream for the Project, including tests for potential impurities that may be present and whether such impurities might alter the corrosivity of the injectate downhole. The information provided in Section 5 was based on the expected chemical and physical characteristics of the CO2 stream and will be used to refine the well operating parameters while maintaining compliance with the Class VI permits.

A sample of the CO2 stream will be collected and analyzed for the suite of parameters listed in Table 5-3 prior to commencing injection and throughout injection operations at the proposed frequency. The details of the sampling process and frequency are described in Section 5 for approval by the UIC Program Director.

Operational Reporting Plan

During the operational phase of the Project, ExxonMobil will report, within 24 hours, a confirmed endangerment to USDWs to the UIC Program Director pursuant to the requirement in 40 CFR 146.88(f)(3); 146.91(c); and 146.94(b)(3), including:

- Evidence that the CO_2 plume or pressure front may endanger a USDW or USDWs;
- The non-compliance situation as it relates to a permit condition;
- Apparent malfunction of the injection system;
- Triggering of a shut-off system or a loss of mechanical integrity; or
- A release of CO_2 to the atmosphere or biosphere.

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO_2 to an unauthorized zone in the event that there is a loss of mechanical integrity.

Injection Well Construction and Operation Summary

The geologic setting for this Project is ideally situated for carbon sequestration because of the geologic properties of the injection and confining zones and the compatibility of the reservoir fluids with CO_2. The Project brings together the proven engineering practices of ExxonMobil in the design of the wells with a state-of-the-art monitoring system and a robust reservoir management strategy. The well designs are engineered to address the potential risks associated with the installation and operation of Class VI injection wells with a primary objective of protecting USDW from the threat of endangerment. The engineering design of the casing setting points, materials, and cement meet and exceed the requirements for Class VI injection well and for the conditions that have been projected for the Project. In addition, the operating strategy is designed to manage the pressure effects of CO_2 injection in the injection zones, to use the available pore space to the fullest extent, and to mitigate potential issues through a robust operational and testing and monitoring strategy.

ATTACHMENT 5: STIMULATION PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Well Stimulation Procedures

In the event it is necessary to achieved desired injectivity, ExxonMobil may stimulate the injection zone for the Rose CCS Project (Appendix D.3). Stimulation may be conducted if injection impairment is observed during the life of the well. Additional details on the stimulation plan can be found in Appendix D.3. Potential causes for injection reduction are:

- Formation damage (e.g., fines migration, scaling, debris in injection stream)
- Geochemical reactions due to fluid / reservoir incompatibility
- Salt precipitation due to in situ brine vaporization
- Reservoir compartmentalization or facies variation
- Shale swelling
- Others

ExxonMobil, will provide advance notice of the proposed stimulation to the UIC Program Director in writing at least 30 days prior to implementation in accordance with 40 CFR 146.91(d)(2). The detailed stimulation plan is provided in Appendix D and incorporates the following:

- Stimulation design to ensure the treatment will not interfere with containment
- Stimulation fluids detail (e.g., volumes, concentrations, additives)

- Stimulation fluid / well material compatibility analysis
- Well Integrity analysis (e.g., casing / tubing stress analysis)
- Stimulation procedure

The stimulation fluids will be an acid, most likely HCl, or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned in the paragraph above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Program Director should a stimulation become necessary:

1. Determine compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.
2. Develop stimulation plan based on the injection impairment cause
3. Provide work procedure and stimulation program to the UIC Program Director in writing at least 30-days prior to the planned date for start of the work (40 CFR 146.91(d)(2)).
4. Prepare wellsite and mobilize equipment
5. Shut-in and isolate the well from the CO2 injection system. Allow the pressures to stabilize
8. Rig up the stimulation equipment.
9. Prepare the well for stimulation.
10. Perform the stimulation treatment as per approved plan.
11. Flush the wellbore with treated water and prepare the well to return to normal operation
12. Rig down and return the well back to injection

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve but is not limited to flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow the injectate to move more readily into the injection formation. Advance notice of all proposed stimulation activities must be provided to the Director, as detailed below, prior to conducting the stimulation. The permittee must describe any fluids to be utilized for stimulation activities and the permittee must demonstrate that the stimulation will not interfere with containment. The permittee must submit proposed procedures for all stimulation activities to the Director in writing at least 30 days in advance, per 40 CFR 146.91(d)(2). Within the 30-day notice period, EPA may: deny the stimulation; approve the stimulation as proposed; or approve the stimulation with conditions. The permittee must carry out the stimulation procedures, including any conditions, as approved or set forth by EPA.

Introduction and Purpose

ExxonMobil may stimulate the injection zones for the Rose CCS Project to enhance the injectivity potential of CO2 injection wells. Stimulation may involve, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces in the injection formation, or other activities that are intended to allow CO2 to move more readily into the injection zone.

ExxonMobil will adhere to all applicable regulatory requirements for any stimulation treatment that may be required. Specifically, and without limitation, ExxonMobil will comply with the following:

- 40 CFR 146.82(a)(9): ExxonMobil will submit the proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment.
- 40 CFR 146.88(a): Except during stimulation, ExxonMobil will ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zones(s). In no case will injection pressure initiate fractures in the confining zones(s) or cause movement of injection or formation fluids that endanger USDW.
- 40 CFR 146.9l(d)(2) and (e): ExxonMobil will notify the Director in writing 30 days in advance of any planned stimulation activities, other than stimulation for formation testing conducted under 40 CFR 146.82. Regardless of whether a state has primary enforcement responsibility, ExxonMobil shall submit all required reports, submittals, and notifications under subpart h of this part to EPA in an electronic format approved by EPA.

The information provided in this section specifically addresses the stimulation fluids, additives, and proposed stimulation procedures ExxonMobil may implement. This plan includes multiple stimulation methodologies that may be selected based on site-specific technical and operational conditions that may impact future well performance. The methods provided below may also be used to remediate scaling or perforation occlusion in the well.

Purpose of the Stimulation

Perforated intervals in the proposed injection zones may require stimulation periodically throughout the project life to enhance performance with the aim of restoring it to initial or optimum conditions. For example, stimulation may be needed to remediate injectivity loss resulting from mineral scales, clay fragments, metallic sulfide, or oxide particulates. Stimulation may also be necessary to remove any near-wellbore damage resulting from drilling and completion operations. Following well construction, remedial stimulation may be conducted before the commencement of CO2 injection.

Stimulation Fluids

ExxonMobil will use acid blends for matrix stimulation that are typical for the industry. These include, but are not limited to, mixtures of acetic, hydrochloric, hydrofluoric, and/or other organic acids. These blends have been historically proven to remove near-wellbore damage caused by mineral scales, drilling muds, completion fluids, and clay fines while minimizing negative impacts to permeability. There is also potential for near-wellbore halite precipitation in the CO2 injectors, which may require remediation by periodic flushes with less saline water.

All chemical treatments will be evaluated and selected for compatibility with the treatment method. For example, mineral acids will be treated with chemical inhibitors to prevent corrosion damage to the tubing string. In addition, chemical systems will be evaluated and selected to avoid damage to the downhole packer sealing elements, casing, and other seals within the injection system that might be exposed to the chemicals.

Additives

Additives may be utilized with the stimulation fluids to aid matrix stimulation while mitigating corrosion of tubulars and potential damage to the sequestration zone. These additives include, but are not limited to, corrosion or acid inhibitors, scale inhibitors, clay stabilizers, biocides, emulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, and/or surfactants. Compatibility of these additives with the stimulation fluids, tubulars and the reservoir will be confirmed prior to their use in any stimulation activities

Diverters

Nitrogen, crosslink polymers, viscoelastic surfactants, solid particulates and/or fiber diverters may be added to stimulation fluids to achieve improved diversion and effective treatment for the target zone by diverting the stimulation fluids to the most impaired (i.e., low injectivity) perforations. Depending on the well-specific requirements and stimulation design, organic or polymeric diverting agents may also be selected. These diverters provide temporary restrictions during stimulation operations and degrade or break-down with time due to water solubility and temperature. The most suitable diverting agent will be selected based on one or more factors, including, anticipated pump rates, the length of the perforated interval, perforation density, and the selected technique for conveying acid to the injection zone (e.g., pumping through regular tubing or pumping down coiled tubing).

Mechanical Stimulation

In addition to chemical stimulation, mechanical stimulation of the well may be required independently, or in conjunction with chemical stimulation. Mechanical stimulation may be required if there is deposition that cannot be easily remediated with chemicals, or if mechanical means may be more effective. These mechanical options include, but are not limited to, backflow, adding perforations, or re-perforating. Perforating operations may be further enhanced with the use of propellants. Propellant stimulations will be designed for nominal height growth, and to remain within the injection zone and avoid fracture growth into the confining layer.

Ensuring Containment

Except during stimulation, injection pressure will not exceed 90% of the established fracture pressure for the injection zone. Injection pressure at the downhole tubing pressure gauge and tubing/annulus surface gauges will be continuously monitored during the stimulation operation. Stimulation of the injection interval will be conducted to avoid affecting the confining layers. .

Stimulation Procedures

A standard stimulation procedure is outlined below. This procedure may be modified depending on site-specific operational and technical conditions and the specific treatment requirements. The conveyance methods may include coil tubing, tubing-conveyed retrievable straddle packer assembly, snubbing unit, tubing flush, or bullheading. The stimulation fluids will be an acid, most likely HCl, or a water-based fluid treated as needed with the necessary chemicals and/or additives to achieve the desired results. Any stimulation would not interfere with the containment of the project. A high-level procedure is as follows and, as mentioned in the paragraph above, a case-specific stimulation plan procedure along with a detailed description of fluids to be used will be provided to the UIC Program Director should a stimulation become necessary:

1. Determine compatibility of stimulation chemicals with well materials, reservoir rock, and fluids.

2. Develop stimulation plan based on the injection impairment cause

3. Provide work procedure and stimulation program to the UIC Program Director in writing at least 30-days prior to the planned date for start of the work (40 CFR 146.91(d)(2)).

4. Prepare wellsite and mobilize equipment

5. Shut-in and isolate the well from the CO2 injection system. Allow the pressures to stabilize

8. Rig up the stimulation equipment.

9. Prepare the well for stimulation.

10. Perform the stimulation treatment as per approved plan.

11. Flush the wellbore with treated water and prepare the well to return to normal operation

12. Rig down and return the well back to injection

ATTACHMENT 6: TESTING AND MONITORING PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Testing and Monitoring Plan

Consistent with the requirements of 40 Code of Federal Regulations (CFR) 146.90, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) developed a comprehensive Testing and Monitoring Plan (Plan) for the Rose Carbon Capture and Storage (CCS) Project (Project) using a risk-based approach. The data collection included injectate monitoring, corrosion monitoring of the well tubular, mechanical, and cement components; pressure fall-off testing; seismic surveying; well logging; continuous monitoring of injection rate and pressure; groundwater quality monitoring; carbon dioxide (CO2) plume and pressure front tracking. The data generated from implementation of the Plan provides the basis to verify the confinement of the injectate in the permitted injection formations during the active injection phase of the Project. The post-injection phase of monitoring is provided in Section 7 – Post-Injection Site Care (PISC) and Site Closure Plan consistent with the structure of the Underground Injection Control (UIC) Class VI Permit Application for the Project. In conjunction with careful site selection and Area of Review (AoR) delineation, this Plan will be a critical component of the successful operation, PISC, and eventual closure of the Project.

A key feature of the Testing and Monitoring Plan is the alignment between the injection operation plan and the geological site features that determine CO2 plume and pressure front migration. This Plan puts forth a data collection plan to confirm that the injection is consistent with the permit requirements. The Testing and Monitoring Plan also includes a phased/triggered approach for the incremental implementation of testing and monitoring technology, consistent with U.S. Environmental Protection Agency's (EPA's) presentation of phased/triggered monitoring in the *Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance*, EPA 816-R-13-001 (Mar. 2013) (available at https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13001.pdf). Overall, the risk of underground source of drinking water (USDW) endangerment is mitigated by balancing the increases in CO_2 plume and pressure front size with the collection and analysis of data to track migration and assess the potential for leaks through the upper composite confining zone (UCCZ) throughout the life of the project.

ExxonMobil intends for the review process for the Plan and subsequent iterations to continue throughout the life of the Project. An adaptive monitoring approach will be employed whereby monitoring frequency of indirect monitoring technologies listed in Table 5.1 may be decreased based on positive test results. Amendments to the Testing and Monitoring plan will be submitted to the UIC Program Director for approval, incorporated into the permit, and subject to permit modification requirements. Monitoring results will be presented in semiannual reports, wherein data will be evaluated, and any monitoring frequency modification would be justified. Baseline data has been collected and comparisons to the baseline data will be made during the operational period of the Project. The adaptive approach will be applied if the data collected during the injection period shows results within the expected range. An ongoing dialogue between ExxonMobil and the UIC Program Director is envisioned, marked by tying the Plan reviews to the AoR reevaluation frequency in adherence to reporting requirements specified in 40 CFR 146.91 . Consistent with the discussion of AoR reevaluation in Section 3 – Area of Review and Corrective Action Plan, a defined schedule is proposed to address situations where there is a change in the AoR or if other circumstances change, while affording an efficient review process if the AoR reevaluation confirms that the Plan is appropriate as written. In this way, testing and monitoring results that indicate corrective action are required to trigger the mitigation measures identified in the AoR reevaluation (Section 3), and the Emergency and Remedial Response Plan (Section 8), if needed, will be triggered at the appropriate time.

Objectives

The following objectives were developed for the Testing and Monitoring Plan in alignment with 40 CFR 146.90:

- Use site characterization data, the site geologic conceptual model, and the results of computational modeling to identify areas or issues of potential concern for the Project;
- Consider how possible leakage pathways and uncertainties in confining zone and injection zone properties could affect the AoR boundaries and include this uncertainty in the testing and monitoring strategy;
- Select testing and monitoring strategies and technologies that are tailored to the site-specific risk profile in conformance with the requirements; and
- Identify Project-specific factors to consider or incorporate in evaluating the data collected from the Testing and Monitoring Plan, which may indicate the potential risk to or endangerment of USDW, as well as deviations from permitted conditions.

Overall Strategy and Approach for Testing and Monitoring Plan

The Class VI Rule requires various testing and monitoring activities to identify potential risks to, and the potential for endangerment of, USDWs. ExxonMobil consulted with the EPA, Region VI UIC Program Director, and the Railroad Commission of Texas (RRC) in pre-application discussions to identify the testing and monitoring activities that were best suited for the Project. The site features that affect the degree of risk and potential for endangerment of a USDW include:

- The integrity of the UCCZ to contain the CO2 plume and pressure front;
- The potential for vertical migration of CO2 and/or brine along faults;
- The occurrence of legacy well penetrations (or "artificial penetrations") through the UCCZ;
- The potential geomechanical stress induced by the modeled injection pressure;
- The engineering design considerations for wellbore cement, casing/tubing materials of construction and completion; and
- Conformance to the modeled operational targets.

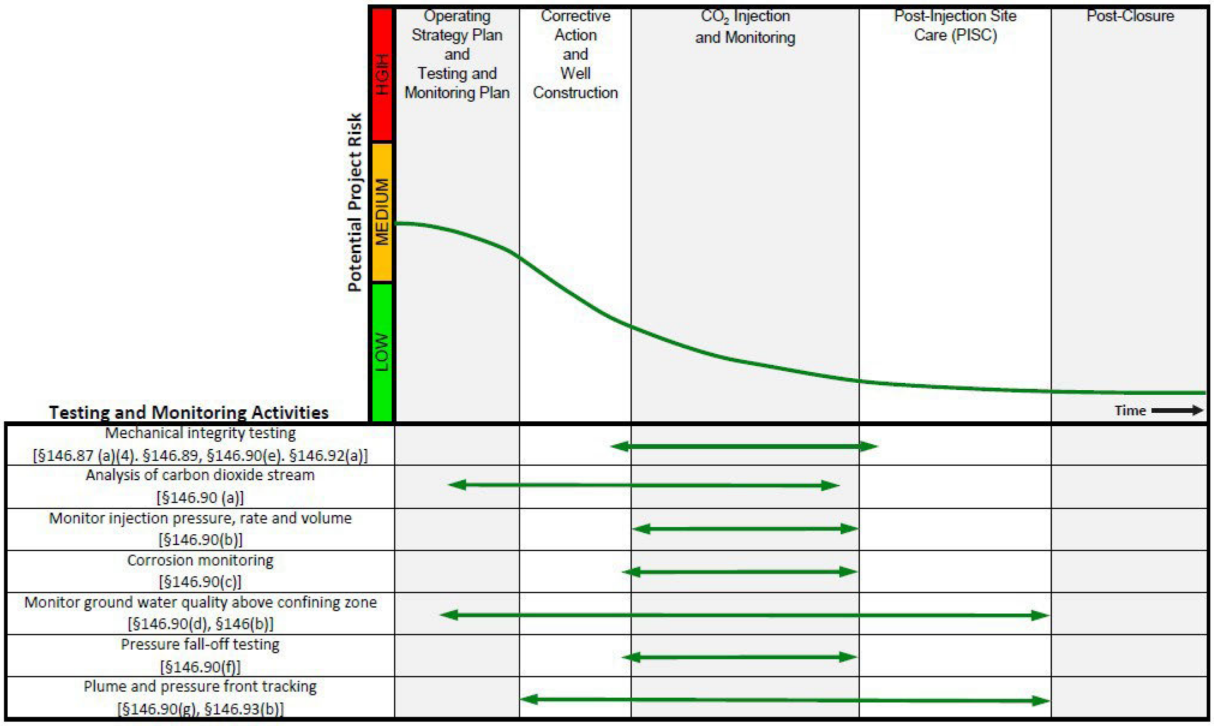
Of these features, the key risk factor that is most critical for the design of this Plan is the potential for legacy well penetrations to create leakage pathways through the UCCZ. ExxonMobil completed a variety of technical tasks discussed in Section 3 – Area of Review and Corrective Action Plan, to identify and evaluate the potential for legacy wells to exist in circumstances where CO2/brine could potentially leak up through a partially plugged wellbore (e.g., with open borehole) or one that is inadequately plugged for CO2 sequestration sites.

Other potential risks associated with the Project were deemed to be of a lower probability and consequence.

Therefore, a focused testing and monitoring approach was considered reasonable and appropriate to address the following risk scenarios:

- Migration of CO2/brine along a fault/fault material or natural fracture impacting USDW;
- Migration of CO2/brine along a fault/fault material or natural fracture impacting USDW due to fault reactivation;
- CO2/brine leaks up unknown wellbore or one inadequately remediated;
- Induced seismicity;
- Loss of external mechanical integrity, which leads to a release of CO2 from injection wells;
- CO2/brine leaks through seal(s) due to lack of seal continuity/presence;
- Unanticipated structural or stratigraphic baffling creates preferential CO2 plume migration pathways; and
- CO2 composition changes and creates excess injection corrosion or unexpected chemical reactions in the injection zone.

Figure 5-1: Summary of the Risk Assessment Process for the Lifecycle of the Project



As shown in Figure 5-1, the anticipated risk level is medium at the pre-operational phase of the Project and is associated with the site characterization and AoR evaluation findings, before implementation of mitigation measures including injection well placement, injection interval selection, operational limitations, and corrective action for artificial penetrations. The injection well locations and injection intervals were selected to provide separation from geologic features (e.g., faults) that could potentially contribute to CO2 or brine crossflow between the injection zone and USDW. Except during stimulation, the maximum injection pressure will be maintained below 90 percent of the fracture pressure of the injection zone(s) to prevent the initiation of new fractures or propagation of existing fractures per the requirements of 40 CFR 146.88(a).

Construction and mechanical integrity testing will be employed to reduce the potential for the loss of external mechanical integrity, which could potentially release CO2. The composition of the injectate stream will be managed and monitored such that unexpected reactions with the potential to impact containment are mitigated. Monitoring and predictive reservoir modeling are being used to limit the potential for CO2 plume and pressure front migration to encounter artificial penetrations that have the potential for CO2 or brine crossflow from the injection intervals to the lowermost USDW.

The accompanying Class VI Rule testing and monitoring requirements address the potential risk scenarios identified by ExxonMobil as warranting monitoring and testing. Scenarios that were found to have elevated risk will be the subject of corrective action prior to operations. Two artificial penetrations (Bead Farm Co. #1 and Broussard J E Jr-1) are located within or near the five-year CO2 plume and pressure front as shown on Figure 3-25. Corrective action has been performed on these wells and the local areas will be monitored as part of the overall monitoring program described in this section. No additional artificial penetrations that penetrate the UCCZ are located within or near the CO2 plume and pressure front. Therefore, a phased corrective action plan is not warranted.

An array of data collection technologies was screened to identify the most reasonable and appropriate methods for the Testing and Monitoring Plan. The screening criteria include: (1) selection of appropriate direct and indirect mature monitoring technologies; (2) cost benefit analysis of each technology to mitigate potential; and (3) a mix between continuous and periodic implementation schedule. ExxonMobil recognizes mature technologies based on their Technology Readiness Levels (TRL), as defined by the International Energy Agency in their report *Energy Technology Perspectives, 2020; Special Report on Carbon Capture Utilisation and Storage.* This scheme is applicable to any technology, including those described in Table 5-1 for implementation on the Project. As described on Figure 5-2, mature technologies are those with TRL 8 (first-of-a-kind commercial demonstration with full-scale deployment in final form) and higher.

The monitoring methods are designed to track the plume in each of the four injection intervals from bottom to top: Upper Frio Sands, Fleming Sands 3, 2, and 1 provided in Figure 5-3.

Figure 5-2: TRLs for Selection of Monitoring Technologies

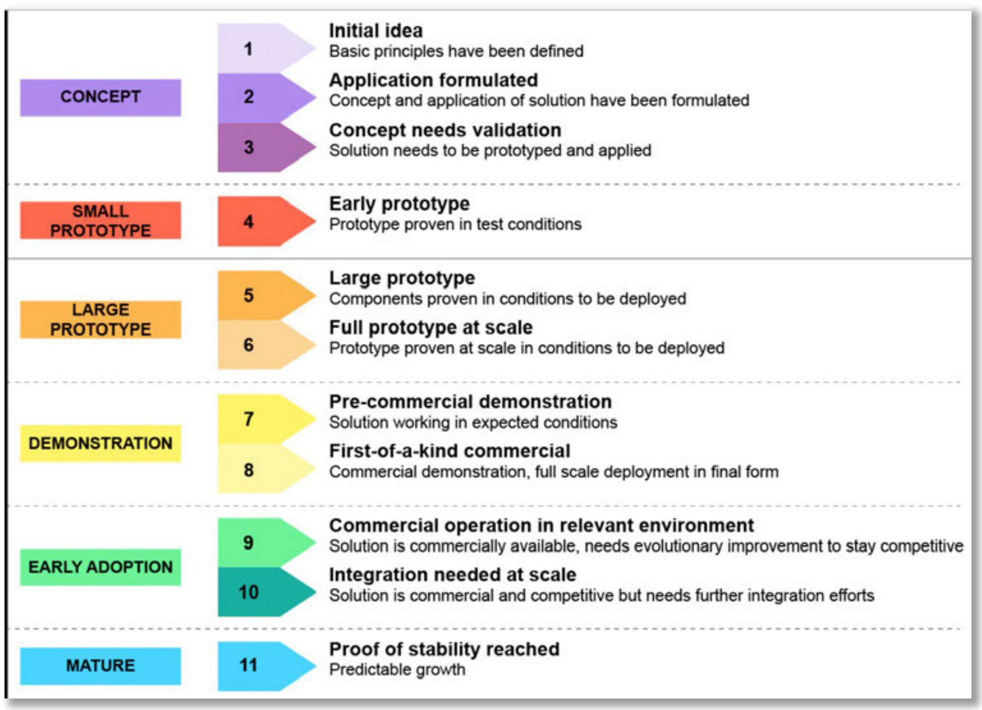


Table 5-1 provides a summary of mature technologies selected for tracking the CO2 plume and pressure front. Consistent with the stated interests of the EPA, the Testing and Monitoring Plan is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring system.

Amendments to the Testing and Monitoring plan will be submitted to the UIC Program Director for approval, incorporated into the permit, and subject to permit modification requirements.

Through the combination of proven and emerging technology pilot testing, a cost-effective testing and monitoring strategy will be maintained for the Project that measures the CO_2 plume and pressure front migration paths and serves to provide reliable data for reevaluating the AoR model.

Table 5-1: Summary of Monitoring Technologies for Direct and Indirect CO_2 Plume and Pressure Front Tracker

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 40 CFR 146.90(g)(1)	Downhole tubing mounted pressure and temperature gauge	Injection Wells No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval Annual pressure fall-off test during well shut-ins	Identify pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure/ temperature gauges	In-Zone Monitoring Well No. 01	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring	CO_2 plume and pressure front tracking
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	Four injection intervals in the Upper Frio and Fleming Formations	No	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after	Monitor CO_2 plume growth in the subsurface over time

						injection, Survey Event #3 within six to eight years after injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	
		Passive Seismicity Monitor Station Array	Selected locations within AoR	Surface	Yes, contingent on triggering seismic event above threshold level determined by Table 8-3: Response Actions for Seismic Events.	Continuous monitoring	AoR-specific seismicity data collection and event analyses
Above UCCZ	Direct per 40 CFR 146.90(g)(1)	Fluid sampling protocol using converted Bead Farm Co. #1 collected through tubing	Above-Zone Monitoring Well - Bead Farm Co. #1	First laterally continuous water-bearing	No	Quarterly samples	Detection monitoring for CO2 plume and/or brine crossflow from

				zone above UCCZ			injection zones to top of UCCZ
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	From surface to base of Frio Sand 2	No.	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after injection, Survey Event #3 within six to eight years of injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary during PISC, as approved by UIC Program Director.	Detection monitoring for presence of CO_2 plume above UCCZ Detection monitoring and evaluation of trends in water quality and geotechnical parameters

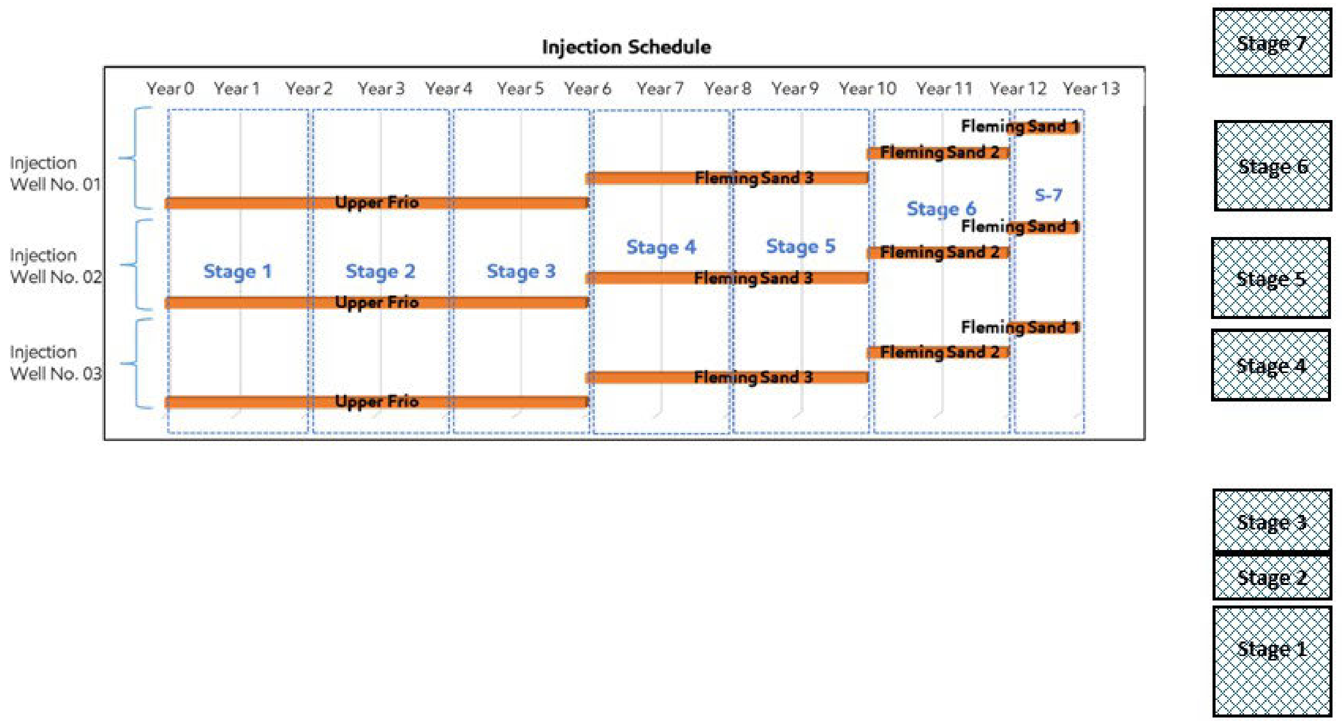
USDW	Direct per 40 CFR 146.90(d)	Fluid Sampling	USDW Monitoring Wells No. 01, No. 02, No. 03	Groundwater samples collected just below the typical total depth of water wells completed in the area (e.g., 300 to 350 ft BGL).	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO2 plume and pressure front tracking as discussed in AoR reevaluations	Pre-Operational Phase – Quarterly Operational Phase – Quarterly	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil Gas Monitoring	Direct per 40 CFR 146.90(h)	Soil gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Direct per 40 CFR 146.90(h)	Portable and/or stationary CO2 detectors monitor record ambient CO2 concentrations	Contingent on confirmed release to USDW				

Use of Phased and/or Triggered Approach

The testing and monitoring plan for CO_2 plume and brine pressure front tracking makes use of the phased and/or triggered approach to scale the testing and monitoring network with the extent of the AoR and the site features that warrant monitoring. The goal of the approach is to provide the data necessary to demonstrate that USDWs are protected from the potential leakage of CO_2 or brine. The scaling aspect of the strategy is aligned with the staged-injection approach outline in Section 3 – Area of Review and Corrective Action Plan that makes use of the vertical profile of the injection zone to optimize the CO_2 storage volume and provides less CO_2 plume and pressure front expansion from year-to-year than would otherwise occur with a more concentrated injection approach. The initial monitoring network is based on the model-predicted five-year AoR and what was deemed appropriate to track the CO_2 plume and brine pressure front during that time period. From that point, the AoR reevaluation process will be used to assess the adequacy of the testing and monitoring program to detect potential leakage should it occur and make recommendations for changes if necessary to demonstrate protection of USDWs.

Figure 5-3 provides an illustration of the staged-injection approach for the Project. CO_2 will be injected at separate stages into four injection intervals in the Fleming and Upper Frio sands, thousands of feet below the lowermost USDW. Rose CCS Project Injection Wells No. 01, No. 02, and No. 03 start injection in the Upper Frio formation and then move to the Fleming formation. Two confining zones are present including the Anahuac Shale and the UCCZ. Additional intraformational shale layers are present within the Fleming and Upper Frio formations. Section 3 – Area of Review and Corrective Action Plan provides a detailed discussion of the injection rates and schedules for each injection well and injection interval.

Figure 5-3: Staged-Injection Approach to Optimize CO2 Storage



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As the CO2 plume and pressure front expand over time, so does the deployment of technology to gather data and assess the potential for USDW endangerment. This phased and/or triggered monitoring strategy was adopted for the Plan based on the timing and depth of each injection interval described in Figure 5-3. The phased and triggered approach was identified as being protective of the USDW because of the availability of mature, reliable, and accurate technologies for tracking the CO2 plume and pressure front within the injection zones while reducing the number of well penetrations through the UCCZ.

The monitoring program was also constructed to align with the three operational phases of the Project: (1) pre-operational baseline data collection phase (cross-referenced in Section 4 – Engineering Design and Operating Strategy); (2) the operational phase for the three injections discussed in this section; and (3) the PISC phase (discussed in Section 7 – Post-Injection Site Care and Site Closure Plan). During the pre- and early-operational phases, a selection of technologies will be used to establish baseline seismic, pressure and certain geochemical parameters needed to monitor the CO2 plume and pressure front. This information will also be used to confirm the predictive modeling results and refine the model as necessary. During the operational phase, the frequency of direct monitoring data collection activities will be aligned with the initiation of injection into each new stage of the injection interval as described in Figure 5-3. The accuracy of the model at predicting the CO2 plume and pressure front migration will inform the frequency of indirect monitoring data collection. Upon confirmation of the predictive capabilities of the model, the frequency of indirect monitoring activities listed in Table 5.1 may be reduced as justified by the rates of change and variations observed by the monitoring results, which are subject to approval by the Director and incorporation into the permit.

A key consideration for the placement of In-Zone Monitoring Well No. 01 and Above-Zone Monitoring Well No. 01 was the need to collect high-quality data that represent the location of the CO2 plume and pressure front for assessing USDW endangerment. The locations of In- Zone Monitoring Well No. 01 and Above-Zone Monitoring Well No. 01 provide useful data relative to the injection permit requirements. A semiannual report will be provided to EPA that presents the collected monitoring data and plume migration evaluations. Surface air and soil gas monitoring [40 CFR 146.90(h)] are proposed as a triggered monitoring condition. The additional use of these technologies will be based on monitoring results obtained from the above UCCZ groundwater and USDW monitoring events.

Mechanical Integrity Test Methods

Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 40 CFR 146.89(b), ExxonMobil assessed the internal mechanical integrity of each injection well by performing annulus pressure tests after the well was completed, will assess again prior to injection, and annually thereafter. Annular pressure testing verifies the Part I or internal integrity of the annulus between casing and tubing above the packer. During well construction, prior to the installation of the injection tubing and packer, the casing was also pressure tested to the maximum anticipated annulus-surface pressure to verify its integrity. Additionally, during well construction and prior to installation of the injection tubing and packer, a casing inspection log was run to confirm the casing integrity.

The annular pressure tests are designed to demonstrate mechanical integrity of the casing, tubing, and packer. These tests will be conducted by pressuring the annulus to a minimum of the planned surface injection pressure described in Section 4 – Well Construction Plan and Operating Conditions.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. As required by 40 CFR 146.91(e), the tubing annulus pressure will be recorded and reported to the UIC Program Director and additional appropriate regulatory permitting authorities, as needed, in semiannual reports to demonstrate compliance with casing integrity requirements.

An annular pressure test was conducted to confirm the integrity of the casing, tubing, and packer as per the following procedure:

- Ensure tubing/casing annulus is filled with fluid;
- Ensure temperature stabilization of well by ceasing injection before and through the test;
- Isolate the annulus pressure system;
- Rig up test pumps onto wellhead, A-Annulus outlet valve and pressure test surface lines to a minimum of planned testing pressure;
- Open casing valve outlet and increase the pressure to a minimum of the planned surface injection pressure as described in Section 4- Well Construction Plan and Operating Conditions;
- Hold pressure for 30 minutes while charting test and continuously monitoring pressure;
- Upon completion of 30-minute interval, check results of tests to confirm that the test has not lost more than 3% of test pressure; and
- Bleed off pressure and report results to UIC.

External Mechanical Integrity Testing

Following the requirements of 40 CFR 146.89(c), ExxonMobil will perform an annual Part 2 external mechanical integrity test (MIT) using both wireline temperature surveys and distributed temperature sensing (DTS) fiber. Wireline temperature surveys will be conducted as part of the regular MIT logging program and compared to DTS fiber measurements until sufficient data has been acquired and reviewed with the UIC Program Director to corroborate the use of DTS for leak detection. DTS fiber has advantages over traditional wireline tools since it is deployed permanently down hole, records at higher resolution, and can be recorded at any time utilizing the DTS interrogator at surface without the logistical challenges of wireline deployment. One of the benefits of this approach is that measurements can be obtained continuously while the well is operating or shut-in.

One fiber optic cable was installed in each injection well for DTS measurements to be collected across the formation intervals of interest. The cable was cemented behind the casing. A DTS interrogator will be available on demand to record temperature data from this fiber optic cable.

If temperature anomalies are observed outside of the permitted zone, ExxonMobil will deploy a Pulse Neutron Logging (PNL) tool in oxygen activation (OA) mode across the anomalous interval to quantify any potential leak rate. The UIC Program Director will be notified of the planned procedure a minimum of 30 days in advance of field activities, per 146.91(d)(3). The actual procedures will be proposed during the notice to the Director, and may vary depending on site, vendor, and equipment factors.

A Pulse Neutron tool is used for the purpose of detecting and quantifying the flow of water in or around the well. A Pulse Neutron test is considered passing when no upward-flow is detected outside of the injection zone. Threshold velocities for false positives will be determined based on the vendor's logging equipment.

Reporting Results of MIT

Annulus pressure test results will be submitted to the UIC Program Director and additional appropriate regulatory permitting authorities, as needed, within 30 days of completion. The logs recorded during external MIT will be submitted to the appropriate regulatory permitting authority such as the UIC Program Director within 30 days of the verification that the logging results are representative and acceptable.

<u>Continuous Recording of Operational Parameters During Injection</u>

ExxonMobil installed and will use continuous measurement devices to monitor injection pressure, rate, and mass injected; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent, and it will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures), and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be determined based on manufacturer recommendations. The automated control system data will be visually monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to determine if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Project will be stored in a database to support AoR reviews, quality assurance / quality control review programs, and routine reporting. Table 5-2 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program. Records will be submitted in an electronic format, per 40 CFR 146.91(e).

Table 5-2: Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes

Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Pressure Gauge	Annulus System Tank	5 seconds	5 minutes
CO2 stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word "continuous" is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected "continuously" will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Continuous Monitoring of Injection Rate and Volume

ExxonMobil will collect continuous measurements necessary to calculate and report the injection mass flow rate and volume in compliance with 40 CFR 146.90(b). A data management system or suitable equivalent will be used to facilitate continuous collection of intake pressure at the central pad transfer point, pressure within the distribution system to each injection well, and the wellhead of the injection wells.

A Coriolis flow meter will be used to measure the flow rate at the central pad and compute flow rates for each injection well. The Coriolis flow meter directly measures the mass flow rate of the injected fluid. Analytical methods will be conducted at a periodic interval to determine the mass percentage concentration of CO2 and carbon monoxide (CO). The mass percentage concentration of CO2 and CO are multiplied by the total mass flow reading from the Coriolis flow meter to estimate the total mass of captured CO2 and CO for a given period. The meter will be placed directly at the point of injection. The meter will be calibrated to manufacturer specifications.

ExxonMobil will review and interpret the continuously monitored parameters to validate that they are within permitted limits. The data review will also include examination of trends to help assess the need for equipment maintenance or calibration. Semiannual reports of the monitoring data will be submitted to the regulatory permitting authority.

Continuous Monitoring of Injection Temperature and Pressure at Injection Well

ExxonMobil will continuously monitor the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 40 CFR 146.90(b). The injected CO2 stream pressure will be continuously monitored in the CO2 flowline near the wellhead interface. The annulus pressure will also be continuously recorded. The combined wellhead and downhole monitoring data will be used to continuously characterize the injection stream in detail.

ExxonMobil will review and interpret the monitoring data to confirm compliance with the operational limits of the injection permit for each well. The data review will include an analysis of trends for operational performance evaluation and routine maintenance. Periodic reports of the monitoring data will be submitted to the UIC Program Director.

Continuous Monitoring of Injection Temperature and Pressure in Reservoir

Reservoir temperatures and pressures will be measured using a downhole gauge installed in the tubing above the production packer. The gauge is shown in detail in Section 4 – Well Construction Plan and Operating Conditions. For specialized data such DTS, the Project will use additional support from the provider of the selected technologies to perform quality control and verification of the data as well as calibration of the systems as needed. See Section 4 for well diagram(s). The Wellhead Pressure Logger will also continuously measure the temperature and can be used as a backup in case the DTS fails.

Continuous Monitoring of Annular Pressure and Volume (Tank Level)

The annular pressure between the tubing and the injection casing string will be monitored on a continuous basis. The pressure gauge on the annulus will be tied into the data management system or a suitable equivalent system and set to alarm if pressure or volumes move outside set tolerances. The annulus tanks in the well systems will be maintained with sufficient volumetric capacity to accommodate the anticipated volume fluctuations due to temperature and pressure variations. The annulus tanks are to be equipped with a level transducer or an armored reflex sight glass and an independent liquid fill nozzle. If any annulus fluid is added or removed, it will be recorded. An annulus tank level is to be recorded on any day when injection occurs.

Positive Annular Pressure

Per 40 CFR 146.88(c), pressure will be maintained in the annulus at a value of at least 100 psi greater than the injection pressure. ExxonMobil will fill the annulus with a non-corrosive fluid approved by the UIC Program Director. A system will be set up to maintain pressure in the annulus using non-corrosive fluid or gas and it will be tied into the alarms or a suitable equivalent system designed to signal pressure drops below set-points.

Corrosion Monitoring

The tubing and casing materials will be monitored during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to demonstrate that the well components continue to meet the minimum standards for material strength and performance. Monitoring will take place based on well-specific conditions that are encountered, with corrosion coupons tested on a quarterly basis.

Monitoring Location and Frequency

Corrosion coupons are placed in continuous contact with the CO2 stream. Corrosion coupons are installed downstream of the central pad facility meter run on the 12-inch header and upstream of the check valves prior to the flow lines to the injection wells. The samples will be exposed to the process stream conditions immediately prior to injection using a recycle loop or sample retriever. Exposure is to be representative of conditions at the top of the tubing. Coupons will be tested quarterly.

Casing inspection logs (CILs) (e.g., ultrasonic imaging tool, electromagnetic, cement bond log, and caliper) will be conducted on the long-string casing at a minimum frequency of once every five years. When the operational monitoring of the plume and/or pressure indicate that a completion stage has been fully utilized and it is time to recomplete uphole to a shallower injection interval, the tubing will be removed and inspected, and a casing inspection logging suite will be run. If the abandonment of an interval is not warranted at the time of recompletion, then a thru-tubing casing inspection will be

Monitoring of Corrosion Coupon

Monitoring of well tubing and casing material corrosion willbe conducted on a quarterly basis to evaluate the corrosion coupon monitoring system. A corrosion coupon station or rack will be provided as part of well-materials integrity monitoring. Any coupon in active use will be exposed to the stream composition to provide ongoing evaluation of material compatibility with the CO2 stream. The results will be reported to the regulatory permitting authority such as the EPA UIC Director semiannually.

The coupons will be assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards. AMPP NACE SP0775-2023 will be followed to assess coupon weight loss and pitting analysis (after baseline). When the coupons are removed, they will be inspected visually for signs of corrosion or pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

The coupon initial baseline measurements will follow the recommendations of ASTM G1-03 (included in references). Coupons will be prepared from the material used to construct the injection well. A method of coupon preparation will be chosen that does not alter the properties of the metal. For example, grinding operations will be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon. Coupons may be prepared by smooth grinding with 120 grit paper, by tumbling with loose grit, or blasting with abrasive blasting material. A consistent finish may be obtained by blasting with glass beads. The abrasives will be free of metallic particles. A permanent serial number shall be etched or stamped on each coupon. ExxonMobil will machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data. ExxonMobil will dry, measure length, measure width, measure thickness, and weigh the coupons to within ± 0.5 mg, record the mass, serial number, and exposed dimensions, calculate the surface area (including the edges) and record. The areas covered by the coupon holder and shielded areas of flush- mounted coupons will be excluded.

Cement Evaluation and Casing Inspection Logs

As discussed in Section 4 – Well Construction Plan and Operating Conditions, a cement bond log was run after the casing was run and cemented and sufficient cement-curing has taken place. Logging was conducted to assess the quality of the cement. A baseline CIL log established the initial dimensions of the wall thickness of the production casing after it was cemented. Following the installation of the completion equipment, including the tubing and packer assembly, an initial electromagnetic through-tubing CIL was run. The CIL will serve as the baseline survey for potential future repeat surveys with the objective of enabling the detection of possible loss of metal mass.

Repeat electromagnetic CILs will only be performed if other monitoring measurements create concern about the integrity of the casing of the well, and the technical determination is made that a repeat CIL is most suitable to address those concerns. Examples include a loss of annulus pressure and temperature measurements using the fiber optic cables installed in the well. Changes in the recorded electromagnetic response will be analyzed to identify and localize casing corrosion, addressing 40 CFR 146.89(d).

Pressure Fall-Off Testing

Required pressure transient fall-off testing will be conducted at the end of every injection stage, prior to recompletion, or every five years, whichever is more frequent, to meet the requirements of 40 CFR 146.90(f). Pressure fall-off tests will be conducted at the staged-injection interval. Recompletion to shallower intervals will result in no further pressure fall-off testing for injection intervals in post-injection status. The objective of periodic testing is to monitor for any changes in the near-well bore environment that may impact permeability and reservoir pressures during active injection. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA within 30 days of the conclusion of the test. Although test procedures or methods may be changed based on request of the permittee and approval by the UIC Program Director, the following procedure is expected to be typical for such periodic monitoring.

Testing Method

The procedures to conduct a pressure fall-off test are as follows:

- Record data regarding test well injection at typical operating conditions (constant rate plus or minus 10%). Rate versus time data will be recorded during the injection period. Cumulative injection volume will also be recorded. Continue injection for a time equivalent to the projected duration of the fall-off necessary to observe analyzable radial flow. Note that significant rate variations may require more complicated analysis techniques.

- Verify operation of permanent monitoring equipment or rig-up downhole memory pressure gauge and run in well to a datum depth approved by the regulators.

- For pressure transient fall-off, obtain final stabilized injection rate and pressure for a minimum of 1 hour. Ensure that the injectate temperature has stabilized.

- Cease injection and monitor pressure fall-off. Continue monitoring pressure for a time sufficient to observe reservoir behavior. Wellbore pressure gradients will be obtained to establish fluid gradient.

- Stop test data acquisition, rig-down and release equipment.

Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, reservoir properties and boundary conditions will be assessed through the use of standard pressure transient diagnostic plotting and well test simulators, as required. This assessment will be accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions will be identified by comparing pressure fall-off tests performed prior to initial injection with later tests. These well parameters resulting from fall-off testing will be compared against those used in AoR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AoR reevaluation is necessary.

The pressure fall-off test results will be submitted to the UIC Director within 30 days of completion of the quality assurance / quality control verification of the pressure data.

Quality Assurance / Quality Control

The surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results. Further validation of the test results will be justified by extended collection of pressure data from the plugged and abandoned injection stages. The continuation of pressure monitoring in deeper, inactive stages allows for recording of the naturally occurring pressure decay. Pressure communication between stages may also be evaluated with this approach.

ExxonMobil developed the Quality Assurance Surveillance Plan (QASP) in Appendix E in this application as a supplement to the testing and monitoring requirements of this section as well as Section 4 – Well Construction Plan and Operating Conditions and Section 7 – Post-Inject Site Care and Site Closure Plan. The goal of the QASP is to provide reliable data to verify that the Project is operating as permitted without endangerment to USDWs. The QASP provides a verifiable set of standards and controls that include the technologies, methodologies, frequencies, sample quality assurance, and procedures to demonstrate the collection data activities will provide accurate and reliable information about the Project operations. The QASP is unique to the Project, informed by site-specific details, monitoring technologies selected, and will be updated as the Project evolves in concert with the Testing and Monitoring Plan.

Monitoring of CO2 Stream

Consistent with 40 CFR 146.90(a), ExxonMobil will install and use measurement devices to analyze the chemical composition of the injection stream to assess the potential for interactions between CO2 and other injectate components and compatibility with the well completions materials. Temperature and pressure will also be measured at the sample collection point.

Sampling Frequency

CO2 stream will be sampled quarterly.

Sampling Methods

The quarterly measurements will be obtained by collecting representative samples of CO2 at a sample port on the Project's central pad beyond the last stage of compression in the compression build or similar point. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO2 stream. The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container. The central pad is the connection point between the CO2 pipeline and the sequestration field's distribution system.

Sampling activities will be conducted at the direction of site representatives and in accordance with the certified or accredited analytical laboratory procedures and will meet the minimum current standard EPA procedures. A sample will be collected by depressurizing the liquid stream and sampling the CO2 as a gas in either a Tedlar® bag, a Summa cannister, or laboratory-approved alternate. The grab sample will be sent to an independent contract laboratory for analysis.

Each sample will be accompanied by a facility or contract laboratory Chain-of-Custody (COC) form that provides a record of sample handling, starting with sample acquisition, documenting the sample transfer process up to laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form. The COC form shall provide the following items recorded by the sampler:

1. Sample ID including code or name, in addition to date and time;
2. Name of sample collector; (include sampling company name if not site personnel);
3. Sample collection method;
4. Sample collection date;
5. Sample collection point; and
6. Sample presentation technique, as applicable.

Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable.

Sample COC will be followed at all times during the sampling and subsequent analysis. COC will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

Analytical Plan

Table 5-3 presents the test parameters, analytical methods, and sample frequency for each test parameter. The selected parameters and constituents for analysis are consistent with the composition of the CO2 stream described in Section 4 – Well Construction Plan and Operating Conditions.

Table 5-3: Summary of CO2 Sampling and Analysis Plan

Parameter/Constituents	Analytical Method(s)[1]	Frequency
CO2 Purity	ISBT 2.0, GC/DID or Method 3A	Quarterly
Water	ISBT 3.0, GC/FTIR, Method 320, EPA Method 4	Quarterly
Oxygen	ISBT 4.0, GC/DID or Method 3A	Quarterly
Nitrogen	ISBT 4.0, GC/DID or by difference	Quarterly
Sulfur Dioxide	ISBT 14.0, GC	Quarterly
Hydrogen Sulfide	ISBT 14.0, GC	Quarterly
Oxides of Nitrogen	ISBT 7.0	Quarterly
Total Hydrocarbons	ISBT 10.0, GC	Quarterly
Carbon Monoxide	ISBT 5.0, GC/DID	Quarterly
Methane	ISBT 10.1, GC	Quarterly
DID = discharge ionization detector; FTIR = Fourier transform infrared; GC = gas chromatography; ISBT = International Society of Beverage Technologists [1] Or suitable alternate analytical method may be used.		

CO2 Plume and Pressure Front Tracking

ExxonMobil plans a two-phased strategy for meeting the requirement for plume tracking consistent with 40 CFR 146.90(g). For the initial period of operation, the rate and direction of CO2 plume migration will be based on continuously recorded pressures and temperatures at the three injection wells and the In-Zone Monitoring Well No. 01. Indirect monitoring will be performed using periodic time-lapse surface seismic imaging. Additionally, ExxonMobil will be exploring emergent technologies to support plume monitoring. The Bead Farm Co. #1 was converted to an Above-Zone Monitoring Well and equipped with tubing for fluid collection. Table 5-1 provides a summary of direct and indirect plume and pressure front monitoring technologies.

Direct Pressure Front Tracking

Injection Wells No. 1, No. 02, and No. 03 (Figure 5-4) are equipped with downhole pressure gauges to continuously monitor the pressure in the active completed injection intervals as shown in Appendix D of Section 4 – Well Construction Plan and Operating Conditions. The continuous pressure and temperature measurements will be used to characterize injection well pressure at that location as well as the cumulative pressure response from the other wells completed in the injection zone.

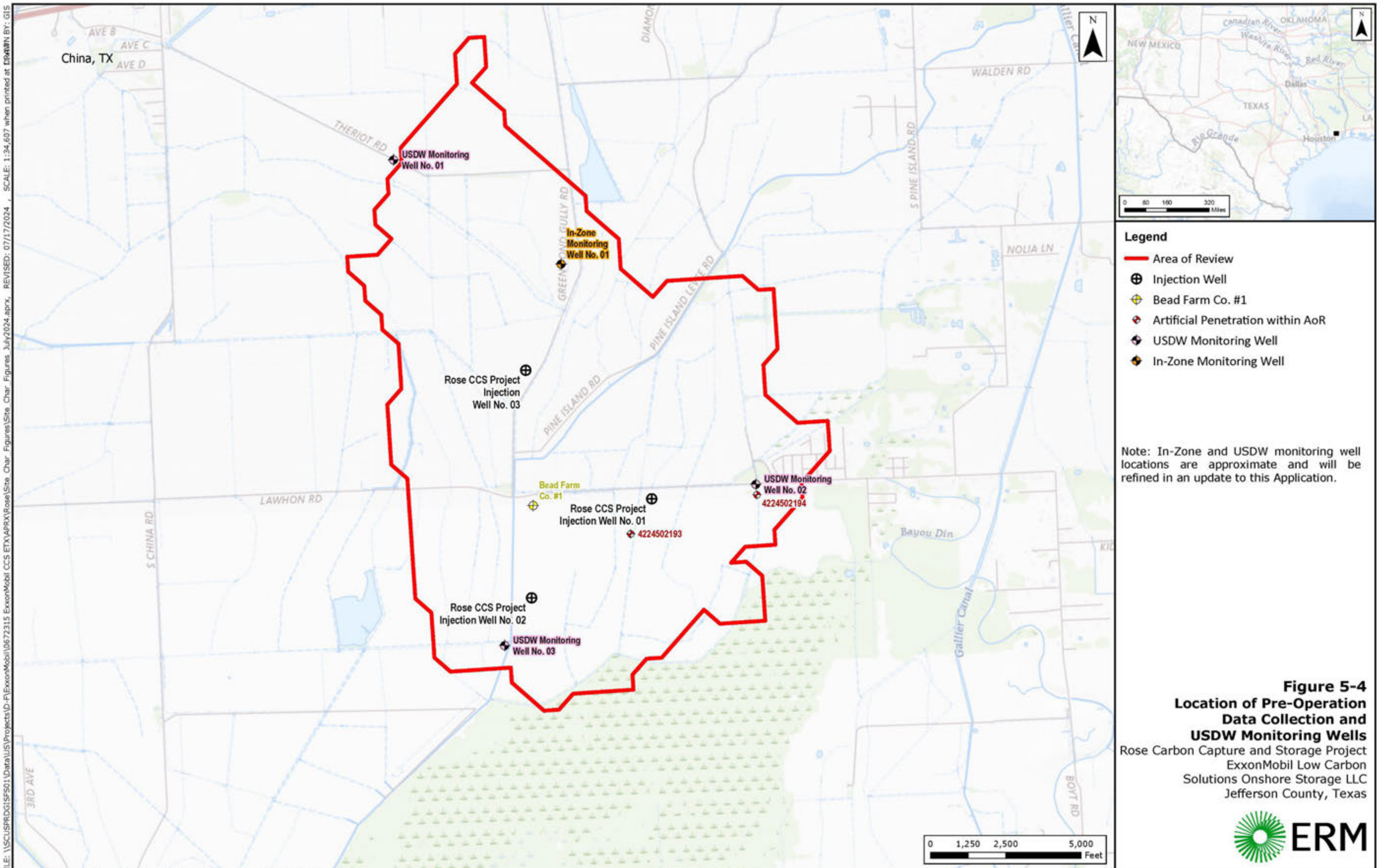

Figure 5-4
Location of Pre-Operation Data Collection and USDW Monitoring Wells
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson County, Texas

Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet

Any periods of shut-in for an injection well may be observed and treated as a fall-off test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continuous measurements obtained during regular operating conditions, will aid in updating the plume models and forecasts.

Plume and Pressure Front Tracking Using Indirect Geophysical Techniques

ExxonMobil will use periodic surface seismic data acquisitions and time-lapse data analysis as the primary indirect method for tracking the CO_2 plume migration consistent with the operation monitoring requirements specified in 40 CFR 146.90(g)(2). An existing 3D-seismic survey will serve as Survey Event #1, representing the pre-injection subsurface characterization baseline and the baseline for time-lapse data analysis. This baseline 3D survey is comprised of two early 2000's vintage proprietary datasets and is undergoing reprocessing by a recognized industry- leading vendor. Surface seismic monitoring surveys will be acquired during the injection stages at a frequency that demonstrates conformance between the reservoir model simulation and site performance. Post-operational survey events will be utilized during the post-injection period to confirm the stabilization of the plume and detect CO_2 leaks through the UCCZ, should they occur.

ExxonMobil considers time-lapse seismic analysis to be a proven method for imaging subsurface changes in oil and gas exploration, enhanced oil recovery (EOR), and production. This methodology has been applied previously by Denbury Inc. in the Frio formation at a Gulf Coast EOR field (Holmes et al., 2023) to monitor the movement of injected CO_2 through time. A summary of the results of this time-lapse surface seismic study are shown in Figure 5-5. The red and yellow colors in Figure 5-5 represent the movement of CO_2 in the Frio formation over time.

Figure 5-5: Results from Time-Lapse Surface Seismic at Gulf Coast EOR Field

CBI

[redacted]

During CO_2 injection operations, seismic data will be acquired periodically in the time-lapse seismic monitoring plan to monitor the movement of the CO_2 plume and calibrate the CO_2 plume model. Survey Event #1 was based on a proprietary survey (referred to as Surface Seismic Survey Event #1 or Survey Event #1) acquired as part of the site characterization data acquisition process to establish an initial state of the subsurface fluid distribution.

The timing of the Survey Event #2 will occur when the following criteria are met and the analysis of operational and testing data demonstrates compliance with the UIC Class VI permits, likely in the first one to three years of operation:

- The UIC Program Director confirms that the data quality objective for direct measurements and operational data have been achieved and no significant deviations related to data quality are outstanding;
- The CO_2 plume and pressure front model has been reasonably calibrated to the actual operational and monitoring results reported to the UIC Program Director;
- The model predicts that the first injection stage is approaching the target storage volume, in compliance with the UIC Class VI Permits for the Project and without threat of endangerment to USDW; and
- The acquisition of indirect monitoring data is necessary to improve the forecast of the end of the initial injection stage and the transition to the next injection stage, while protecting USDW from endangerment of CO_2 or brine cross-flow.

Should at any time the acquisition of indirect monitoring data suggest deviation from expected behavior for compliance with the permits, ExxonMobil will discuss the need with the UIC Permit Director and take appropriate action.

Survey Event #3 will occur in the Fleming formation approximately six to eight years after stage 1 startup using the same approach from the injection stages in the Upper Frio Sands.

Survey Event #4 is planned for approximately thirteen years of operations. A significant amount of direct and indirect monitoring data will be available, up to 16 semiannual reports provided to the UIC Program Director, and conclusions made regarding the predictive capabilities of the CO_2 plume and pressure front model for both the Upper Frio Sand and the Fleming Sand injection intervals. ExxonMobil expects that the model will be a reliable predictor of the growth rates and extents of CO_2 saturation and pressure plumes. With the UIC Program Directors concurrence, Survey Event #4 will occur at the end of operational period, a predicted total of 13 years. Survey Event #4 will yield the indirect measurement of the extent of the CO_2 plume at the start of the PISC period.

As described in Section 3 – Area of Review and Corrective Action Plan, the maximum pressure differential within the injection zone diminishes rapidly to just above baseline pressures within the first year of PISC for the Fleming Sands, which is the portion of the injection zone immediately beneath the UCCZ. The decrease in maximum pressure differential in the Upper Frio Sands also drops significantly after year seven of the injection schedule. After injection in the Frio is completed, the model results predict a steady decline to a maximum pressure differential [redacted] when injection ceases, indicating plume stability. This rapid decline in pressure in the injection zone, along with the performance of the calibrated model, are the primary bases for recommending that no additional surface seismic events may be necessary in the PISC period. In the event that additional surface seismic events are necessary to improve the model's predictive capability or show CO2 plume stability, ExxonMobil will communicate with the UIC Program Director on the nature and timing of such contingent survey events.

In summary, ExxonMobil proposes the following surface seismic monitoring event schedule:

- Survey Event #1: completed as part of the data purchase and reprocess for site characterization;
- Survey Event #2: one to three years from start of operation assuming the triggering criteria are met;
- Survey Event #3: six to eight years from start of operations with conformance to the triggering criteria;
- Survey Event #4: expect to occur at the end of the operations, 13 years from commencement of operations
- The survey event time increment is not to exceed 5 years and may be shortened, conforming to triggering criteria defined by the UIC Program Director; and
- Contingent Additional Survey Events during Operational and PISC Phases: to be determined based on the results from direct and indirect monitoring and model prediction.

The time-lapse data collected during survey events will also be used to monitor for CO2 in the groundwater formation directly above the storage reservoir, utilizing data from both the injection wells and the in-zone monitoring well as an assurance-monitoring technique.

The timing of these survey events will be refined in future updates of the monitoring plan according to 40 CFR 146.90(j). Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

CO2 Plume Tracking Using Groundwater Monitoring Data

Phased and Triggered Monitoring

The phased and/or triggered monitoring strategy was adopted for the installation of potential additional USDW monitoring wells, soil gas monitoring wells, and air monitoring locations. The phased approach was deemed reasonable and appropriate based on the schedule of CO2 injection for three injection wells and the degree of protectiveness evident based on the geologic site characterization and demonstrated by the plume modeling. This type of approach allows the site-specific testing and monitoring strategies to be tailored to changes in predicted performance and in response to potential increased risks to USDWs identified or detected during the course of injection.

Table 5-4: Summary of Phased and/or Triggered Monitoring Program

Phase	Establish Baseline Conditions	Tracking and Monitoring Initial CO2 Plume and Pressure Front Migration	Sustained Operating Conditions
Time Period	Conducted prior to injection.	From start of operations until at least 50 years after cessation of injection or for the duration of an alternative time frame approved through a successful non-endangerment demonstration.	From end of initial CO2 plume and pressure front tracking to cessation of injection operations, assumed to be 13 years from start.
Description	Measure baseline conditions in the injection zone, above UCCZ, and in USDW for comparison with subsequent detection monitoring data collection.	CO2 plume and pressure front tracking at three injection wells and one in-zone monitor well using direct and indirect technologies as well as groundwater sampling at the above- zone monitoring well and three USDW monitoring wells to demonstrate compliance with the permit requirements.	Continued monitoring with an appropriate number of monitoring wells to track the CO2 plume and pressure front within the AoR, monitor the groundwater, and demonstrate compliance with permit requirements.

Monitored Conditions	Injection Wells: wellhead and bottomhole pressure and temperature measurement. Bead Farm Co. #1: pressure, temperature, groundwater samples collected at selected intervals for baseline groundwater quality and geochemical parameters during well drilling. Additional baseline groundwater sample(s) collected above UCCZ during conversion to Above-Zone Monitoring Well. Survey Event #1: baseline acoustic response of surface to base of Upper Frio Sands. USDW monitoring wells: groundwater quality and geochemical parameters.	Injection Wells: wellhead and bottomhole pressure and temperature. In-Zone Monitoring Well: injection interval pressure and temperature. Above-Zone Monitoring Well: Groundwater samples from first laterally continuous water-bearing zone above UCCZ for water quality and geochemical parameters. Survey Events: three acoustic response events from surface to base of Upper Frio Sands to assess CO2 plume growth within the AoR. USDW monitoring wells: water quality and geochemical parameters.	Injection Wells: wellhead and bottomhole pressure and temperature. In-Zone Monitoring Well: injection interval pressure and temperature. Above-Zone Monitoring Well: Groundwater samples from first laterally continuous water-bearing zone above UCCZ for water quality and geochemical parameters. Contingent Survey Events: to be conducted if additional indirect evidence of CO2 plume stabilization is warranted. USDW monitoring wells: groundwater quality and geochemical parameters.

Planned Changes in Monitoring Techniques	None	Frequency of USDW monitoring is quarterly	Additional USDW monitoring wells as needed to characterize geochemical variability in accordance with CO2 plume migration and pressure front.
Monitoring Locations	Three injection wells One In-Zone Monitoring Well One Above-Zone Monitoring Well (Bead Farm Co. #1) Three USDW monitoring wells Seismic: CO2 Plume Area	Three injection wells One In-Zone Monitoring Well One Above-Zone Monitoring Well Three USDW monitoring wells Seismic: CO2 Plume Area	Three injection wells One In-Zone Monitoring Well One Above-Zone Monitoring Well Three to seven USDW monitoring wells Seismic: CO2 Plume Area

Monitoring Frequencies	Injection Wells: single event measurements and samples at time of installation In-Zone Monitoring Well: continuous pressure and temperature measurements for each injection interval. Above-Zone Monitoring Well: Quarterly fluid samples from first water-bearing zone above UCCZ for two years. Stratigraphic Test Well: single event measurements and samples at time of installation USDW Monitoring Wells: Quarterly Survey Events: Survey Event #1 baseline event prior to start of operations	Injection Wells: continuous pressure and temperature. Annual pressure fall-off testing during shut-in. In-Zone Monitoring Well: continuous pressure and temperature measurements for each injection interval. Above-Zone Monitoring Well: Quarterly fluid samples from first water-bearing zone above UCCZ USDW Monitoring Wells: quarterly fluid samples Survey Events: Survey Event #2 within first one to three years after injection, Survey Event #3: six to eight years into injection, Survey Event #4: at 13 years from start of operations. Contingent additional survey events as needed and approved by UIC Program Director.	Injection Wells: continuous pressure and temperature. Survey events at reasonable time periods to confirm CO2 plume tracking and demonstrate compliance with permit requirements. Annual pressure fall-off testing during shut-in. In-Zone Monitoring Well: continuous pressure and temperature measurements for each injection interval. Above-Zone Monitoring Well: Quarterly fluid samples from first water-bearing zone above UCCZ USDW Monitoring Wells: Annual fluid samples. Survey Events: None planned. Sufficient data, model calibration, and rapid declines in maximum pressure differential are expected to reduce the need for subsequent surface seismic events during PISC. Contingent additional survey events as needed and approved by UIC Program Director.

Triggers	Expand list of geochemical parameters and install additional USDW monitoring wells if unexpected trends or variability are apparent.	Table 3-21 in Section 3 – Area of Review and Corrective Action Plan provides a list of triggers for the AoR reevaluation process. Those triggers are applicable to the monitoring program.	Table 3-21 in Section 3 – Area of Review and Corrective Action Plan provides a list of triggers for the AoR reevaluation process. Those triggers are applicable to the monitoring program.

Note: The word "continuous" is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application.

Measurements that are collected "continuously" will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.

Design of the Monitoring Well Network

The monitoring well network includes the monitoring wells that will be used to support compliance with the testing and monitoring requirements under the Class VI Rule. Combined with the monitoring of pressure build-up at each injection well, the design of the monitoring well network was selected to provide a high degree of confidence in detecting a leak through the confining zone that may endanger USDW. The relevant site data considered for the design of the monitoring well network included the phased injection depths, rate, and volume; the geology, and the presence of the legacy wells as required at 40 CFR 146.90(d)(1) and (2).

USDW Monitoring Well Construction

To comply with 40 CFR 146.90(d), a phased approach to USDW monitoring well installation is proposed. Initially, three USDW monitoring wells were completed at the locations shown on Figure 5-4. These locations were selected to provide a baseline of geochemical data in the vicinity of the following areas of significant interest:

- Within the Footprint of the Projected CO2 Plume and Adjacent to Public Water Supply: USDW Monitoring Wells No. 01 and No. 02 are located within or near the underlying CO2 plume and in alignment with potential CO2 plume migration toward of the northwest, (toward China, Texas) and in the vicinity of the 9000 to 10500 Block of Lawhorn Road, Beaumont, Texas. The available information suggests that both areas may rely on USDW for potable supply.

- Downgradient of the Injection Wells: USDW Monitoring Well No. 03 is located south of the three injection wells in the anticipated direction of groundwater flow in the Chicot Aquifer. This well will provide groundwater quality measurements downgradient from the highest CO2 plume pressure.

The Chicot Aquifer is the most prolific USDW aquifer within the AoR, and its relatively shallow water-bearing zones are a target for completion of water wells, typically at depths ranging from approximately 150 to 400 feet (ft) below ground level (BGL) in the AoR. The depth of the USDW monitoring wells was selected to be consistent with the total depths of water wells in the area and will provide data to assess whether significant changes in water quality are occurring at the depth of most water wells. These three USDW monitoring wells will provide an initial baseline of USDW quality prior to injection and then monitor for changes in USDW quality during injection and PISC.

CBI [redacted] The bottom of the USDW was confirmed by both literature review and through the collection of open-hole wireline logs at the stratigraphic well (Bead Farm Co. #1) in November 2023, confirming the literature-cited depths of the lowermost USDW. The close correlation of the top of the Evangeline Aquifer and the elevated concentrations of TDS above 10,000 mg/L was sufficient evidence that monitoring groundwater quality at this depth could have a high potential for false positive detections of brine presumed to be associated with brine leakage through the UCCZ. For this reason, no USDW monitoring wells were located in the Evangeline Aquifer.

Other potential leakage points were considered for USDW monitoring wells, but the available evidence and evaluation indicated that no significant risk was apparent. For example, the model simulations of pressure near fault planes were found to be below levels deemed necessary to cause transmissivity that might result in the potential for CO_2 and/or brine to leak from the injection zones to USDW. Along-fault fluid migration is not a significant risk because as shown in Section 2.5.9.2 of Section 2 – Site Characterization, Shale Gouge Ratio (Yeilding et al., 1997) values of greater than 90% within faults intersecting confining intervals demonstrate robust fault seal, well above a conservative 50% cut-off, and significantly higher than the empirically determined value of 15-20% (Manzocchi et al. (1999); Sperrevik et al. (2002)). The critical pressure front does not intersect Fault 2_2, the only fault that extends through the UCCZ (Section 2.5.9.2 of Section 2 – Site Characterizatoin). Therefore, no USDW monitoring wells were proposed near fault planes. The time-lapse seismic monitoring collected during operations will be used to validate the model prediction of pressure and fault transmissivity.

Amendments to the Testing and Monitoring plan will be submitted to the UIC Program Director for approval, incorporated into the permit, and subject to permit modification requirements. At this time, it was assumed that up to four additional USDW monitoring wells, if necessary, could be completed in a phased approach to expand USDW monitoring coverage commensurate with the expanse of the CO_2 plume and pressure front. The target schedule for expansion is after an initial period from the start of operations. During this time, data will be collected to reduce the uncertainty in CO_2 plume and pressure front migration. The locations of any potential additional USDW monitoring wells will be selected for areas where a risk of leakage either remains uncertain or plume and pressure tracking indicators that a leakage feature, such as a legacy well, warrant additional groundwater monitoring.

Summary of Water Well Data for the AoR

Table 5-5 provides a summary of the USDW monitoring well construction details for USDW Monitoring Wells No. 01, No. 02, and No. 03. The well construction details for additional USDW monitoring wells (if constructed) will be consistent with the construction details in Table 5-5.

A total of 11 water wells in addition to the project monitoring wells were identified in and near the AoR as listed on Table 5-6 from the Texas Water Development Board well registration list and the Texas Commission on Environmental Quality environmental well database. Appendix F- 1 illustrates the location of the water wells. Each of these wells is completed in the Chicot Aquifer with a maximum depth of approximately 440 ft BGL. The Project will monitor pressure and CO_2 plume growth using indirect seismic measurements, water samples collected from USDW Monitoring Wells No. 01, No. 02, and No. 03 (Table 5-5), and measurements of temperature and pressure from In-Zone Monitoring Well No. 01. If the growth of either the pressure or CO_2 plume is found to exceed the expected growth based on corroboration of multiple of the above-mentioned measurements, the Project will reevaluate the need for additional USDW groundwater monitoring wells. Expected growth will be defined by the modeled plume size (Section 3.7 of Section 3 – Area of Review and Corrective Action Plan).

This will be prioritized near local communities or densely populated areas.

Table 5-5: Summary of USDW Monitoring Well Construction Details

USDW Monitoring Well	NAD83 (2011)	Latitude	NAD83 (2011)	Longitude	Total Depth (ft BGL)	Screened Interval (ft BGL)
USDW Monitoring Well No. 01	30°01'51.6497"	30.0310138	-94°18'38.9290"	-94.3108136	330	300-320
USDW Monitoring Well No. 02	30°00'09.5150"	30.0026431	-94°16'28.5845"	-94.2746068	350	320-340
USDW Monitoring Well No. 03	29°59'15.7081"	29.9876967	-94°17'56.3342"	-94.2989817	330	300-320

Table 5-6: Summary of Available Water Well Completion Details for AoR

Well Report ID	NAD83 (2011)	Reported Latitude	NAD83 (2011)	Reported Longitude	Well Type	Well Owner	Date Completed	Borehole Depth	Status or Plugging and Abandonment Date
645970	29° 59' 56.49" N	29.99903	94° 17' 53.14" W	-94.2981	Rig Supply	Exxon Mobil	8/11/2023	290	In Use
6162901	30° 0' 4.98" N	30.00139	94° 16' 14.86" W	-94.2708	Plugged and Destroyed	D. S. Wier	8/27/1941	7	Not Available
670175	29° 59' 59.49" N	29.999857	94° 16' 59.56" W	-94.28321	Water Rig Supply	Exxon Mobil	6/14/2024	300*	Active
670177	29° 59' 26.58" N	29.990716	94° 17' 55.08" W	-94.298632	Water Rig Supply	Exxon Mobil	7/2/2024	300*	Active
674757	30° 00' 44.74" N	30.012428	94° 17' 52.47" W	-94.297908	Water Rig Supply	Exxon Mobil	7/19/2024	300*	Active
675893	30° 01' 19.01" N	30.021947	94° 17' 39.12" W	-94.294199	Water Rig Supply	Exxon Mobil	8/15/2024	300*	Active

678489	30° 00' 09" N	30.0025	94° 16' 28" W	-94.274444	Monitoring Well	Exxon Mobil	8/20/2024	440*	P&A Date 11/5/2024
689934	29° 59' 57.37" N	29.99927	94° 17' 8.34" W	-94.28565	Monitoring Well	Exxon Mobil	9/19/2024	25*	Active
689935	29° 59' 26.23" N	29.99062	94° 17' 54.96" W	-94.2986	Monitoring Well	Exxon Mobil	9/17/2024	25*	Active
689936	30° 00' 44.57" N	30.01238	94° 17' 52.69" W	-94.29797	Monitoring Well	Exxon Mobil	9/17/2024	25*	Active
689937	30° 00' 9.65" N	30.00268	94° 16' 26.51" W	-94.27403	Monitoring Well	Exxon Mobil	9/18/2024	20*	Active

1 groundwater sample per well will be collected using decontaminated submersible pumps equipped with new dedicated and disposable sampling tubing capable of producing representative groundwater samples to the surface with the least pumping effort. The fluid sampling parameters and frequencies for the above-zone and USDW monitoring wells are shown in Table 5-8. Additional USDW monitoring wells will be added to assess the potential for USDW endangerment if necessary. Well completion diagrams are provided for USDW Monitoring Wells No. 01 to No. 03 in Appendices F-2 to F-4.

Construction of In-Zone Monitoring Well and Above-Zone Monitoring Well (Bead Farm Co. #1)

In-Zone Monitoring Well No. 01

In-Zone Monitoring Well No. 01 was constructed to collect pressure and temperature measurements from the four injection intervals. Table 5-7 provides the completion details for the well. In-Zone Monitoring Well No. 01 was equipped with a tubing encapsulated conductor cable with in-line pressure/temperature gauges to collect continuous pressure and temperature measurements for evaluating the rate of CO2 plume and pressure front movement. A schematic of In-Zone Monitoring Well No. 01 is provided in Appendix F-5.

In-Zone Monitoring Well No. 01 was constructed up-dip from the location of the three injection wells (Figure 5-4) to establish direct measurements of pressure and temperature in the injection intervals at a non-active location.

The In-Zone Monitoring Well No. 01 was equipped with a fiber optic gauge cemented behind the production casing. As shown on Appendix F-5, a fiber optic cable was cemented in the annulus of the long-casing string of the in-zone monitoring well for annual mechanical integrity testing.

Above-Zone Monitoring Well No. 01

After abandoning the injection interval, Bead Farm Co. #1 was converted to an Above-Zone Monitoring Well to collect groundwater samples from the first laterally continuous water-bearing zone above the UCCZ. Table 5-7 provides the completion details for the well. The Above-Zone Monitoring Well was equipped with a tubing string and packer as a conduit to collect groundwater samples. A schematic of the Above-Zone Monitoring Well No. 01 is provided in Appendix F-5.

The Above-Zone Monitoring Well No. 01 is centrally located from the location of the three injection wells (Figure 5-4) to establish direct measurements of groundwater samples in the injection intervals at a non-active location.

Once operations commence, groundwater samples will be collected from the first laterally continuous water-bearing zone above the UCCZ via the Above-Zone Monitoring Well No. 01 for analysis of geochemical concentrations on a quarterly frequency for the operational period.

Continuous pressure and temperature measurements will be recorded in In-Zone Monitor Well No. 01 for semiannual reporting using a downhole pressure gauge (illustrated in Appendix F-5 as a tubing encapsulated conductor cable and gauges mounted behind the casing). The primary line of evidence for assessing whether a threat to USDW is apparent will be based on a geochemical data assessment. Pressure and temperature trends will be considered as secondary lines of evidence and will be evaluated to assess significance of trends and the potential for instrumentation error to have caused false or erroneous measurements.

No additional monitoring wells were deemed necessary at this time based on the model-predicted CO_2 plume movement and monitoring program, the significant porosity/permeability thickness and layering present in the injection zones and the extensive UCCZ present at the site. In the event of unexpected CO_2 plume migration, the location of additional monitoring wells will be proposed through a revision to this Testing and Monitoring Plan.

Table 5-7: General Details for In-Zone and Above-Zone Monitoring Wells

Monitoring Well Location Info	Above-Zone Monitoring Well No. 01 (Bead Farm Co. #1)	In-Zone Monitoring Well No. 01
NAD83 (2011) Latitude	29°59’57.1992”N	30°01'16.85"N
NAD83 (2011) Longitude	94°17’50.5093”W	94°17'37.65"W

Collection and Analysis of Groundwater Samples

One fluid sample per well will be taken periodically from the USDW monitoring wells and Above- Zone Monitoring Well No. 01 (Bead Farm Co. #1). The Above-Zone Monitoring well will target the first laterally continuous sand above the UCCZ, which is approximately 1,000’ below the base of the USDW. The USDW monitoring wells target the Chicot Aquifer, which is the most used aquifer in the AoR for potable and non-potable purposes. The sampling frequency for the Above-Zone and USDW monitoring wells is quarterly. This quarterly sampling characterizes the potential seasonal fluctuation in this USDW.

Table 5-8 summarizes the parameters analyzed and the planned sampling frequency, which apply to the USDW and Above-Zone Monitoring wells. Anomalous measurements will trigger re-sampling and additional data analysis, including a more detailed evaluation of data using statistical comparisons approved by EPA for detection monitoring programs. This analysis could also include geochemical modeling to compare the compositions of groundwater from before and during operations.

If warranted, other tests may be added to the evaluation if re-sampling and detailed analysis of the fluid samples does not satisfactorily rule out a leakage scenario.

Table 5-8: USDW and Above UCCZ Monitoring Sampling Program

<table>
<tr><th>Parameter/Analyte</th><th>USDW Monitoring Well Frequency</th><th>Monitoring Frequency above the UCCZ</th></tr>
<tr><td>TDS, alkalinity, electrical conductivity, temperature, pH</td><td rowspan="2">Quarterly</td><td rowspan="2">Quarterly</td></tr>
<tr><td>Gas composition (CO_2, CH_4, O_2, N_2)</td></tr>
</table>

Dissolved cations (Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn)		
Dissolved anions (HCO3, B(OH)4, Br, CO3, Cl, F, I, NO3, NO2, PO4, SO4, S)		
Note: Ba = Barium; B(OH)4 = Tetrahydroxyborate; Br = Bromide; Ca = Calcium; Cd = Cadmium; CH4 = Methane; Cl = Chloride; CO2 = Carbon dioxide; CO3 = Carbonate; Co = Cobalt; Cr = Chromium; Cu = Copper; F = Fluoride; Fe = Iron; HCO3 = Bicarbonate; I = Iodide; Li = Lithium; Mg = Magnesium; Mn = Manganese; Mo = Molybdenum; N2 = Nitrogen; Na = Sodium; Ni = Nickel; NO2 = Nitrite; NO3 = Nitrate; O2 = Oxygen; P = Phosphorus; K = Potassium; PO4 = Phosphate; Si = Silicon; SO4 = Sulfate; Sr = Strontium; S = Sulfur; TDS = Total Dissolved Solids; V = Vanadium; Zn = Zinc		

Analytical Methods

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-8. Both in-field pH measurements and laboratory-based chemical analysis will be performed. If results indicate the existence of impurities in the injection stream, the significance of these constituents relative to the protection of USDW will be assessed to determine if they should be included in the analysis of the water samples. Testing results will adhere to the reporting requirements as outlined in 40 CFR 146.91(e).

Fluid chemistry data will be monitored for deviations from baseline values. During the injection phase as baseline data is still being collected, the concentration range for the baseline will be taken as the arithmetic mean of all currently collected baseline data +/- 35%. This assumes that laboratory analyses will have an uncertainty of ~25% and aquifer inhomogeneity will contribute an additional ~10% uncertainty. If deviations from the baseline are outside of this range, the numerical model will be reevaluated. Following the injection phase where a statistically robust dataset for the baseline will be available, the concentration range for the baseline will be taken as the arithmetic mean of the baseline data +/- the 95% confidence interval. If deviations from the baseline are outside of this range, the numerical model will be reevaluated.

Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Change in TDS;
- Change in signature of major cations and anions;
- Increase in CO2 concentration;
- Decrease in pH;
- Increase in concentration of injectate impurities; and
- Increase in concentration of leached constituents.

Laboratory to be Used/COC Procedures

The fluid samples will be transported to an accredited and state-approved laboratory for analysis. ExxonMobil will observe standard COC procedures and maintain records to allow full reconstruction of the sampling procedure, storage, and transportation, including any problems encountered.

Quality Assurance and Surveillance Measures

ExxonMobil will collect replicate samples and sample blanks for quality assurance / quality control purposes. The samples will be used to validate test results, if needed.

Plan for Guaranteeing Access to All Monitoring Locations

Placement of the well locations is optimized to be accessible from roads.

Injection Interval Monitoring

In-zone fluid samples were collected from the stratigraphic test well and were analyzed for water quality and geochemical parameters. The results of these tests were provided in Section 2 – Site Characterization, Appendix B.1. In-zone fluid sampling is not proposed as a monitoring mechanism. ExxonMobil plans to monitor CO_2 plume growth via time-lapse surface seismic, which is better suited to tracking three-dimensional plume growth than fluid sampling (which is a point measurement). Pressures and temperatures will be monitored in all injection intervals CBI [redacted] through seventeen gauges installed in the In Zone Monitoring Well. This combination of surface seismic and continuous in-zone pressure temperature measurements will aid in the tracking and modeling of the CO_2 plume and pressure front over time.

Seismic Monitoring (Induced Seismicity)

Based on the projected operating conditions and regional and local geologic conditions, injection operations are not expected to result in an induced seismic event mandating a response action. However, ExxonMobil has installed a permanent seismicity monitoring system onsite, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since 1 July 2024. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time, high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. ExxonMobil will additionally receive notifications from USGS of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that the event was within a 5.6 mi radius of an injector (as specified in Table 8-3), ExxonMobil will notify the UIC Program Manager to jointly determine if the events are likely to be associated with the operations, and, if so, implement response actions for seismic events as contained in Table 8-3.

Reporting Requirements

The Testing and Monitoring Plan was developed to achieve two reporting objectives:

- Provide the necessary data to verify predictions of CO_2 plume and pressure front movement; and
- Provide the basis for evaluating the model inputs, making necessary changes, and reevaluating the AoR.

In compliance with 40 CFR 146.91, ExxonMobil will provide reports to the UIC Program Director in routine semiannual reports that document the performance of the system and CO2 plume and pressure front tracking data. Relevant records pertaining to the Class VI Testing and Monitoring program will be submitted to the EPA. In addition, ExxonMobil will follow the prescribed notification requirements for deviation from permit conditions, operational malfunction that may allow CO2 or brine to migrate into or between USDWs, or for other evidence of USDW endangerment.

The semiannual reports will include the data collected during each reporting period and a list of notifications triggered during a semiannual period, if any. The following information is proposed for the routine performance reporting:

- Monthly average, maximum, and minimum values of injection pressure, flow rate and volume, and annular pressure;
- Monthly volume and/or mass of the CO2 stream injected over the reporting period, and the volume injected cumulatively over the life of the Project;
- Monthly annulus fluid volume added;
- Results of CO2 plume and pressure front tracking as described herein;
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO2 stream from the proposed operating data that could impact plume migration or protection of USDWs
- A description of any event which triggered a shut-off device required to 146.88 (e) and the response taken; and
- A description of any event that exceeded operating parameters for annulus pressure or injection pressure specified in the permit.

The semiannual reports will be submitted 30 days after the completion of the quality control, quality review of the data for each reporting period. Table 5-9 describes the non-routine reporting triggers, contents, and schedule.

Table 5-9: Summary of Triggering Events for Notification and Reporting Schedule

Triggering Event	Reporting Schedule
Planned well workover, stimulation activities, or other planned test of an injection well.	Notification to the UIC Director, in writing, 30 days in advance of planned activity.
Completion of well workover.	30 days after completion of well workover.
Any test of the injection well conducted, if required by the UIC Director.	30 days after completion of any testing required by UIC Director.
Evidence of potential non-compliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs.	Verbal Notification – Reported within 24 hours of non-compliance or malfunction.
Evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW.	Verbal Notification – Reported within 24 hours of endangerment

A failure to maintain mechanical integrity.	Verbal Notification – Reported within 24 hours of MIT failure
A change in CO2 concentration that results in a value less than or equal to 96% [% = mol % = volume %] in the injection stream. The injection stream will be >97% carbon dioxide. A significant deviation which would warrant notification to the UIC director is if that stream changes to a valueless than or equal to 96%.	Written Notification – Reported within 72 hours of concentration change.
An operational condition that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit.	Verbal Notification – Reported within 24 hours of non-compliance with permit conditions. Written Notification – Reported within 72 hours of non-compliance with permit conditions.
A shut-off device anywhere in the injection well system that is triggered.	Verbal Notification – Reported within 24 hours of event. Written Notification – Reported within 72 hours of event.

ExxonMobil will submit all reports, submittals, and notifications to both the EPA and the RRC and retain records in accordance with 40 CFR 146.91(f) for a 10-year period after site closure. Additionally, injected-fluid data, including nature and composition, will also be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

Testing Plan Review and Updates

In accordance with 40 CFR 146.90(j), the Testing and Monitoring Plan will be reviewed and revised at a minimum of every five years to:

- Identify Project-specific factors that may warrant revision to the Plan;
- Incorporate information and changes necessary to monitor an increase in risk to or endangerment of USDWs; and/or
- Deviations from permitted conditions that require Plan modifications.

ExxonMobil will incorporate the collected monitoring data that characterizes the Project-specific factors and the changes needed, if any, to monitor increased potential risk to USDW and overall Plan compliance with the UIC Director's requirements. Plan amendments will be submitted within one year of an AoR reevaluation, following significant facility changes (such as addition of monitoring wells or newly permitted injection wells within the AoR), or as the UIC Director requires. Table 5-10 summarizes the various measurements discussed in the Testing and Monitoring Plan and the frequency of measurements for data collection and reporting purposes.

Table 5-10: Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	Regulation	Objective	Frequency
Coriolis flow meter	146.90b	Measure mass flow rate	Continuously
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Quarterly
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing Pressure gauge	146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus Pressure gauge	146.90b	Verify annulus pressure maintained	Continuously
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Annually
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	146.90f	Measure fall-off of pressure after abandoning injection stage and initiating injection in next stage above	At the end of every injection stage

	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Continuously
Time-lapse surface seismic survey	146.90g(2)	Indirect method to monitor CO2 plume growth in the subsurface over time	Frequency from start of operations: Survey Event #1: completed; Survey Event #2: one to three years; Survey Event #3: six to eight years; Survey Event #4: 13 years. Contingent additional survey events as needed and approved by UIC Program Director.
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	One-time event
	146.90e	DTS to assess potential flow through channels through or along cement	Annually
Injection well CIL	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent or upon request by UIC Program Director
In-zone monitoring well downhole P/T gauge	Not required	Potential to detect pressure anomaly [redacted] in case of leakage; will require careful analysis due to false positive potential from sensor drift, geomechanical effects, and preexisting pressure trends due to potential far-field activities	Continuously

Above-zone monitoring well fluid sampling from above UCCZ	146.90d	Above UCCZ fluid collection is recommended by guidelines	Quarterly
USDW fluid sampling	146.90d	Sample fluids from the Chicot Aquifer which is the most prolific USDW aquifer within the AoR, as recommended by guidelines, and analyze composition	Quarterly

Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application.

Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.

ATTACHMENT 7: WELL PLUGGING PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Injection Well Plugging Plan

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting this Underground Injection Control Class VI permit application to the United States Environmental Protection Agency for the Rose Carbon Capture and Storage (CCS) Project (Project).

ExxonMobil is undertaking the Project in Jefferson County, Texas, to sequester a maximum of 5 million metric tonnes per annum of carbon dioxide (CO2) using three injection wells over an injection period of up to 13 years. The predicted total CO2 storage is 53 million metric tonnes.

The Injection Well Plugging Plan section for the Project Class VI Underground Injection Control (UIC) Permit Application was prepared to meet the requirements of the Code of Federal Regulations, Title 40, Section 146.92 [40 CFR 146.92] and Texas Administrative Code, Part 1 Title 16 Chapter 5 for plugging and abandonment (P&A) of the Rose CCS Project Injection Wells No. 01, No. 02, and No. 03. The purpose of the Plugging Plan is to demonstrate the actions that ExxonMobil will take to mitigate the threat to underground sources of drinking water (USDW) during the post-injection period.

ExxonMobil has obtained a substantial amount of data and analyses from the core sampling and analysis program for the Project's stratigraphic well (Bead Farm Co. #1; American Petroleum Institute 4224532908). This data has been incorporated into the Area of Review model to show the extent of the CO2 plume and critical-pressure front and the operating strategy for CO2 storage.

In alignment with Statewide Rule §5.203(k)(1)(C) ExxonMobil has selected materials for plugging the injection wells that will resist the corrosive properties of the injection fluid to maintain mechanical integrity of the plug and well casing. The planned plugging procedures are aligned with best practices for restoring the upper composite confining zone (UCCZ) integrity at each injection well location. ExxonMobil has a staged perforation schedule for the injection wells to optimize the storage of CO_2. As a result, multiple injection well “plug-back” events will be undertaken to move from one injection interval to the next prior to permanent well closure. Once the storage capacity has been reached, the last injection interval and the remainder of the injection well will be plugged for final abandonment.

Separately, the procedures and details for the stratigraphic well P&A are included in this plan for completeness purposes.

Objectives

The Plugging Plan represents one of the final steps in the lifecycle of each of the three injection wells for the Project. ExxonMobil will properly plug and abandon the injection wells, maintain the integrity of the UCCZ throughout the remainder of the post-closure care period, and monitor the performance of the plugged wells to contain CO_2 and brine in the injection zone, reducing the potential risk of USDW endangerment.

The Plugging Plan and procedures were designed to meet the following objectives:

- Measure the bottomhole reservoir pressure prior to conducting plugging activities [40 CFR 146.92(b)(1)];
- Assess the external mechanical integrity of the long-string casing by using appropriate testing methods to demonstrate isolation consistent with 40 CFR 146.92(b)(2);
- Select the type, grade, and quantity of material to be used in plugging to withstand contact with CO_2 and acidified liquids in the injection intervals [40 CFR 146.92(b)(5)]; and
- Detail the methods, locations, and types of plugs used within the well [40 CFR 146.92(b)(4) and 40 CFR 146.92(b)(6)].

Preparation of Well Prior to Plugging

Prior to plugging, the well will be flushed with a kill weight fluid, the bottomhole pressure will be measured, well components will be removed as needed, and an external mechanical integrity test (MIT) will be performed. The proposed plugging methods and materials used are corrosion compatible to the injection interval conditions.

As needed, ExxonMobil will repair deficiencies identified during the life of the well to mitigate potential leaks to USDWs [40 CFR 146.88(f)]. Historical MIT data and prior remedial measures will be considered prior to plugging operations. If required, those remedial activities will be included in an amendment to this plan.

Flushing Well with Kill Weight Fluid

Pressure control will be accomplished through the use of kill weight brine that is weighted and compatible with the injectate and formation fluids. The brine will be weighted to provide a minimum [redacted]. The kill weight brine fluids will be circulated through the injection well to remove fluids or fine debris that could have a significant impact on the integrity of cementing operations. The following components that have been in contact with injection or annular fluids will be flushed:

- Any components in the annular space between the injection tubing and the production casing;
- The long-string casing;
- The perforated injection zone; and
- The injection packer, if needed.

[redacted]. After the well has ceased operation, flushing fluid will be circulated through tubing to flush the well of free solids, as necessary.

Removal of Well Components and Obstructions

The removal of well equipment prior to plugging will be completed at the end of the injection period for each well with the objective to open the well for access. In general, uncemented and non-permanent components of the well will be removed. This includes downhole monitoring devices and potentially shut-off devices. The tubing will be pulled from the well.

The surface and long-string casings will be cemented to the surface and will remain in place.

Planned Tests or Measures to Determine Bottomhole Pressure

Prior to each interim plug-back from total depth and prior to permanent abandonment, ExxonMobil will measure the bottomhole reservoir pressure using the downhole pressure temperature (DHPT) gauge installed above the packer as discussed in Section 4 – Well Construction Plan and Operating Conditions. The bottomhole pressure will be calculated by multiplying the CO_2 gradient by the difference in depth between the DHPT gauge and top of perforation, and adding this to the pressure observed at the DHPT gauge, i.e., BHP = (CO_2 gradient x (top perforation – DHPT depth)) + DHPT Pressure gauge. The bottomhole reservoir pressure will be used to estimate the density of kill weight brine needed to establish static equilibrium prior to plug placement.

Planned External MITs

MIT will be used to identify that there is no significant leak in the casing, tubing, or packer; and there is no significant fluid movement into a USDW through channels adjacent to the injection wellbore [40 CFR 146.89(a)]. ExxonMobil will conduct on an annual basis at least one of the tests listed in Table 6-1 as part of the monitoring program, to verify external mechanical integrity as required in 40 CFR 146.92(a).

Table 6-1: External MIT Methods

Test Description	Method of Testing
Temperature Log	Wireline log and distributed temperature sensing with fiber cable installed in the wells
Oxygen Activation/Pulse Neutron Log	Wireline log

The results of the MIT will be documented and provided to the UIC Program Director once per year in digital form.

If any deviation from the baseline logs performed with respect to the UCCZ and potential flow toward USDW are identified, the UIC Program Director will be informed and an investigation will be performed.

Conditions that constitute a pass/fail for the MIT logs are as follows:

- Temperature Log: A potential breach of CO2 out of zone can be identified by changes in temperature profile above the UCZ compared to baseline logs and other post-injection logs. Cooler than expected temperature anomalies above the UCZ may indicate integrity issues and further logs will be performed to investigate the anomalies.

- Pulse Neutron Log in Oxygen Activation mode will be run to confirm fluid movement and quantify rate.

CO2-Compatible Materials

In accordance with 40 CFR 146.92(b)(3) and (5) and Statewide Rule §5.203(k)(1)(C), a cement that is compatible with CO2 will be used as the UCCZ cement plug. The procedures for corrective action on artificial penetrations of the UCCZ were described in Section 3 – Area of Review and Corrective Action Plan. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations with concurrence of the UIC Program Director. The intent is to select a cement system that is designed to provide a long-term cement sheath or plug that can withstand the temperature, pressure, and chemical interactions.

Cement at intervals above the UCCZ will be based on Class H cement. A list of common cement additives is provided in Table 6-2 for the Class H cement to improve setting time, reduce porosity, and improve overall strength if needed. ExxonMobil will report the wet density and will retain duplicate samples of the cement used for each plug in the plugging reports.

Table 6-2: Common Cement Additives

Additive Type/Category	Additives
Fluid-loss additive	• Cellulosic polymers • Polyamines • Sulfonated aromatic polymers • Polyvinyl pyrrolidone • Polyvinyl alcohol • Acrylamido methyl propane sulfonate copolymers and terpolymers • Bentonite • Latexes • Crosslinked polyvinyl pyrrolidone
Dispersant	• Polynapthalene sulfonate • Polymelamine sulfonate
Retarder	• Lignosulfonates • Hydroxycarboxylic acids • Cellulose derivatives • Organophosphonates • Certain inorganic compounds
Accelerator	• Calcium chloride • Sodium chloride • Sodium silicates
Antifoam agent	• Polyglycol ethers • Silicones

Mechanical plugs will generally be used for intra-zonal isolation of injection intervals. At the UCCZ, a plug may be set in a nipple profile if packer is present prior to pumping a minimum of 130 feet (ft) of CO2-compatible cement.

Planned Site Restoration Activities

After the injection wells have been plugged and abandoned, the wellhead equipment and surface facilities will be removed from the well site. The surface will be restored to a condition agreed upon by the landowner and by the UIC Program Director, as appropriate.

Injection Well Zonal Isolation and Final P&A

As discussed above, a plug will be set for injection zone isolation and the final P&A will occur at the end of the Project. The following details outline the procedures for both types of plugs to be installed. The volume and depth of the plugs will depend on the final geology and downhole conditions of the well as assessed during final plug and abandon operations.

Zonal Isolation and Intermediate Plug-Back Plan

The injection wells will be completed in multiple intervals within the gross injection zone. Each injection interval will be used for a discrete period (or stage). Once that period has concluded the newly completed portion of the injection interval will be isolated to reduce the potential for crossflow conditions to occur. After an injection stage has been isolated, the production casing will be perforated to create a new injection interval. The perforations will occur from bottom to top, starting in the Upper Frio and sequentially moving up to the Fleming Sand 3, 2, and 1 injection intervals.

When a current completion interval has reached the end of its injection period for each well, that set of perforations will be isolated and abandoned. The general procedure for zonal isolation of completion stages within each injection well are defined below.

Pre-Zonal Isolation Activities

ExxonMobil will comply with reporting and notification provisions for the UIC Program Director, which require a 60-day advanced written notice before planned recompletion efforts are undertaken [40 CFR 146.92(c)]. A similar notice of recompletion will be communicated to the Railroad Commission of Texas (RRC). The bottomhole reservoir pressure will be measured using the DHPT gauge installed above the packer [40 CFR 146.92(a)]. Schematics of the initial completion for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03 are presented in Appendix D.1.

Zonal Isolation Activities

A barrier will be set above the injection zone to be isolated. This is generally completed via a bridge plug or a permanent packer with plug in nipple profile completed with approximately 20 ft of cement. Based on literature review, SPE 12141 suggests the minimum cemented footage required for zonal isolation within 9-5/8” casing would be 15’. Pursuant to Texas Railroad Commission (TRRC) Statewide Rule §3.14 (g)(3), 20' of cement is to be placed on top of the mechanical bridge plug/packer with plug in nipple profile. With the planned plug, in addition to production casing cement, a 20’ plug was deemed acceptable for zonal isolation for the injection stages. The plug integrity will be assessed by conducting a pressure test or tagging. The perforations will not be squeezed.

Final P&A

After injection operations cease and after post-operational monitoring in a well is completed, the injection well will be prepared for final P&A. The general final P&A procedures are described below.

Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions and provide written notification to the UIC Program Director 60 days before planned plugging efforts. If changes have been made to the original approved Injection Well Plugging Plan, ExxonMobil will provide the amended Injection Well Plugging Plan [40 CFR 146.92(c)]. A Notice of Intention to Plug and Abandon Form W-3A will be submitted to the RRC at least 5 days before plugging operations are planned to commence. In accordance with 40 CFR 146.92(d), a plugging report will be submitted to the UIC Program Director and RRC within 60 days after plugging. Plugging Record Form W-3 will be filed with RRC District Office 3 within 30 days after plugging.

The following plugging activities are planned for each injection well:

- The bottomhole reservoir pressure will be measured using the DHPT gauge installed above the packer [40 CFR 146.92(a)];
- The external mechanical integrity will be demonstrated through approved testing methods discussed above [40 CFR 146.92(a)]; and
- The injection well will be flushed with a kill weight fluid prior to pulling the injection tubing and packer [40 CFR 146.92(a)], as described in Table 6-3.

Table 6-3: Description of Casing, Tubing, and Other Well Construction Materials to be Removed

Well Component	Size	Injection Well No. 01 Amount	Injection Well No. 02 Amount	Injection Well No. 03 Amount	Notes / Comments
26 lb/ft L80-13Cr Tubing	7 in.	3,501 ft KB	3,510 ft KB	3,412 ft KB	Tubing and gauges will be pulled prior to P&A operations
KB = Kelly Bushing; lb/ft = pound per foot					

Plugging Procedure, Injection Well No. 01

The following sequence of plugging procedures are planned:

CBI

[redacted]

CBI

[redacted]

Plug Details, Injection Well No. 01

Table 6-4 provides the plugging details for Injection Well No. 01; Appendix H shows the final plugged schematic.

Table 6-4: Plug Details for Injection Well No. 01

Plug Description	UCCZ Plug	Surface Casing Shoe Cement Plug	USDW Plug	BUQW Plug	Superior Water Quality Plug	Surface Cement Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in which Plug Will Be Placed	8.5 in.	8.5 in.	8.5 in.	8.5 in.	8.5 in.	8.5 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,500 ft KB	2,203 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft
Sacks of Cement to be Used (each plug)	43	44	41	41	37	11
Slurry Volume to be Pumped (ft3)	51	47	43	43	39	12

Slurry Weight (lb/gal) [1]	14.5	16.4	16.4	16.4	16.4	16.4
Top of Plug (MD)	3,370 ft KB	2,083 ft KB	1,429 ft KB	1,177 ft KB	650 ft KB	0 ft
Bottom of Plug (MD)	3,500 ft KB	2,203 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft
Type of Cement or Other Material	CO_2 compatible cement	Class H	Class H	Class H	Class H	Class H
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
Type of Plug	Balance	Balance	Balance	Balance	Balance	Balance
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes

ft^3 = cubic feet; lb/gal = pound per gallon; MD = measured depth from KB

[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability

Slurry Volume (ft^3) = ID^2/1029.4 × plug height (ft) × 5.615

CO_2-compatible Class H cement slurry yield: 1.207 ft^3/sack; Portland Class H cement slurry yield: 1.08ft^3/sack

ExxonMobil's current plan for the UCCZ plug is to utilize Halliburton's proprietary Corrosalock blend or suitable equivalent. However, ExxonMobil plans to revisit blends to incorporate potential future advancements in CO_2-compatible cement that may be available at the time of final abandonment. Any changes to the plugging plan will be provided in the required Notice of intent to plug per 40 CFR 146.92(c).

Notifications and Record Keeping

The procedures described above are subject to modification during execution, as necessary, for implementation of plugging operations that protect worker safety and the USDW. Significant modifications due to unforeseen circumstances will be reported to the UIC Program Director within 24 hours of occurrence during field operations and documented in the plugging report.

Completed plugging forms, records, and lab information will be supplied to the regulatory agencies as required by the permit. The plugging report will be certified as accurate by ExxonMobil and the plugging contractor and will be submitted to the UIC Program Director within 60 days after plugging is completed [40 CFR 146.92(d)]. Well plugging reports, post- injection site care data (including data and information used to develop the demonstration of the alternative post-injection site care timeframe), and the site closure report collected pursuant to the requirements in 40 CFR 146.93 (f) and (h), will be retained by ExxonMobil for 10 years following site closure. Site closure and reporting is discussed in Section 7 – Post-Injection Site Care and Site Closure Plan.

The plugging report will provide the following information:

- Results of tests to determine BHP and mechanical integrity;
- Type and number of plugs used;
- Cement type, grade, weight, and quantity of material for plugs;
- Method of cement plug emplacement; and
- Top and bottom of each cement plug.

<u>Monitoring Wells P&A</u>

Monitoring wells must be plugged in accordance with 40 CFR 146.93(e) to not allow movement of injection or formation fluids that could endanger USDWs. Specific monitoring wells will remain in place after injection wells have been plugged and abandoned for use in monitoring activities associated with the Post Injection Site Care and Site Closure Plan. ExxonMobil will assess the monitoring well plugging procedures prior to P&A in relation to this plan. Documentation of appropriate P&A of the monitoring wells will be submitted to the UIC Program Director in accordance with 40 CFR 146.93(f)(1).

Plugging Procedure, In-Zone Monitoring Well No. 01

The following sequence of plugging procedures are planned:

CBI

[redacted]

CBI

[redacted]

Table 6-7: Plug Details for In-Zone Monitoring Well No. 01

Plug Description	UCCZ Plug	Surface Casing Shoe Cement Plug	USDW Plug	BUQW Plug	Superior Water Quality Plug	Surface Cement Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in which Plug Will Be Placed	4.8 in.	4.8 in.	4.8 in.	4.8 in.	4.8 in.	4.8 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,400 ft KB	2,183 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft
Sacks of Cement to be Used (each plug)	14	14	13	13	12	4
Slurry Volume to be Pumped (ft^3)	16	15	14	14	13	4
Slurry Weight (lb/gal) [1]	14.5	16.4	16.4	16.4	16.4	16.4
Top of Plug (MD)	3,270 ft KB	2,063 ft KB	1,429 ft KB	1,177 ft KB	650 ft KB	0 ft
Bottom of Plug (MD)	3,400 ft KB	2,183 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft

Type of Cement or Other Material	CO2 compatible cement	Class H	Class H	Class H	Class H	Class H
Method of Emplacement	Circulation	Circulation	Circulation	Circulatio n	Circulatio n	Circulatio n
Type of Plug	Balance	Balance	Balance	Balance	Balance	Balance
New Plug?	Yes	Yes	Yes	Yes	Yes	Yes

ft^3 = cubic feet; lb/gal = pound per gallon; MD = measured depth from KB

[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability

Slurry Volume (ft^3) = $ID^2/1029.4$ × plug height (ft) × 5.615

CO2-compatible Class H cement slurry yield: 1.207 ft^3/sack; Portland Class H cement slurry yield: 1.08 ft^3/sack

Plugging Procedure, Above-Zone Monitoring Well No. 01 (Bead Farm Co. #1)

The following sequence of plugging procedures are planned:

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Table 6-8: Plug Details for Above-Zone Monitoring Well No. 01 (Bead Farm Co. #1)

Plug Description	UCCZ Plug	Surface Casing Shoe Cement Plug	USDW Plug	BUQW Plug	Superior Water Quality Plug	Surface Cement Plug
Plug Number	1	2	3	4	5	6
Diameter of Boring in which Plug Will Be Placed	8.5 in.	8.5 in.	8.5 in.	8.5 in.	8.5 in.	8.5 in.
Depth to Bottom of Tubing or Drill Pipe or Mechanical Base (MD)	3,527 ft KB	2,225 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft
Sacks of Cement to be Used (each plug)	64	44	41	41	37	11
Slurry Volume to be Pumped (ft^3)	77	47	43	43	39	12
Slurry Weight (lb/gal) [1]	14.5	16.4	16.4	16.4	16.4	16.4
Top of Plug (MD)	3,332 ft KB	2,105 ft KB	1,429 ft KB	1,177 ft KB	650 ft KB	0 ft
Bottom of Plug (MD)	3,527 ft KB	2,225 ft KB	1,539 ft KB	1,287 ft KB	750 ft KB	30 ft

Type of Cement or Other Material	CO_2 compatible cement	Class H	Class H	Class H	Class H	Class H
Method of Emplacement	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation
Type of Plug	Balance	Balance	Balance	Balance	Balance	Balance
New Plug?	No	Yes	Yes	Yes	Yes	Yes

ft^3 = cubic feet; lb/gal = pound per gallon; MD = measured depth from KB

[1] Proposed slurry density may be modified as needed due to field conditions and vendor availability

Slurry Volume (ft^3) $= \frac{ID^2}{1029.4} \times plug\ height\ (ft) \times 5.615$

CO_2-compatible Class H cement slurry yield: 1.207 ft^3/sack; Portland Class H cement slurry yield: 1.08ft^3/sack

Amendments to the P&A Plan

The Plugging Plan will be amended to account for changes in conditions that trigger modification to the Area of Review. ExxonMobil will inquire with the UIC Program Director to confirm whether such changes in condition warrant amendments to the Plugging Plan. Approval for revisions to the Injection Well Plugging Plan will be requested from the UIC Program Director. Any approved changes to the Plugging Plan will be incorporated in the permit and are subject to permit modifications. Notifications of intent to plug will be provided to the UIC Program Director at least 60 days prior to conducting the plugging activity [40 CFR 146.92(c)].

ATTACHMENT 8: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Post-Injection Site Care and Site Closure Plan

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting this Underground Injection Control Class VI Permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage the Project in Jefferson County, Texas to sequester a maximum of (CO2) using three injection wells over an injection period of up to total CO2 storage is . This Post-Injection Site Care (PISC) and Site Closure Plan is submitted in compliance with the requirements of the Code of Federal Regulations, Title 40, Section 146.93 [40 CFR 146.93] and Texas Administrative Code, Part 1, Title 16, Chapter 5.

The PISC Plan describes the activities that will occur once injection operations have ceased, and the Project moves into maintaining a non-endangerment condition for underground sources of drinking water (USDW). The Site Closure Plan will be implemented once ExxonMobil demonstrates to the Underground Injection Control (UIC) Program Manager that no additional monitoring is required to demonstrate protection of USDW and that the testing and monitoring system can be dismantled. ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in Section 5 – Testing and Monitoring Plan of the Application. The major monitoring elements include continued measurements of the CO_2 plume and pressure front location, monitoring above upper composite confining zone (UCCZ) groundwater as well as USDW. The data collected from this activity will be used to confirm compliance with the water quality objectives for the Project and generate information needed to support the final non-endangerment demonstration and subsequent site closure. The end of the Project comes when the closure activities have been documented and approved by the UIC Program Director.

Objectives

The PISC and Site Closure Plan have been developed to meet the following objectives as outlined in 40 CFR 146.93:

- Describe the pressure differential between pre-injection and predicted post-injection pressures in the injection zones as well as the predicted positions of the CO2 plume and associated pressure front at site closure;
- Describe the post-injection monitoring locations, methods, and proposed frequencies to demonstrate non-endangerment to USDW over the timeframe of the PISC;
- Identify the pre-closure, plugging, and site-restoration steps to achieve approval for site closure; and
- Outline the documentation and recordkeeping practices that will provide the information for decision-making purposes.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default PISC monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. Once the non-endangerment demonstration has been approved, ExxonMobil will plug the monitoring wells, restore each well pad to the landowner's agreed-upon condition, and submit a Site Closure Report to the UIC Program Director.

Calculation of Pre- and Post-Injection Pressure Differentials

As described in 40 CFR 146.93(a)(2)(i), the Class VI non-endangerment demonstration will establish that pressure has declined to a level that no longer poses potential endangerment of USDW. For the purposes of this section, ExxonMobil evaluated the pressure differentials by comparing the pre-operating pressure with the post-injection pressure differentials predicted by the plume model. The predicted pressure differential between pre-injection and the modeled post-injection pressures are favorable, showing a steep and continuous decline in pressure toward pre-operational baseline conditions. The primary mechanisms responsible for the anticipated pressure decay rates are the injection sequencing plan, the geological conditions of the injection zones (e.g., net sand thickness, permeability, porosity) and confining zones, and the projected CO2 storage volume for the Project site.

A staged injection sequence is planned for the injection wells to optimize the storage of CO2 in the three Fleming Sand injection intervals (from uppermost to lowermost Fleming 1, Fleming 2, and Fleming 3) and the Upper Frio injection interval. Section 3 – Area of Review and Corrective Action Plan and Section 4 – Well Construction Plan and Operating Conditions of the application provide detailed discussions of the injection sequencing strategy. Figure 7-1 summarizes the injection sequence schedule for the proposed 13-year injection period. The actual injection period will depend on the issuance of the permits for each injection well.

Figure 7-1: Proposed Injection Interval Schedule

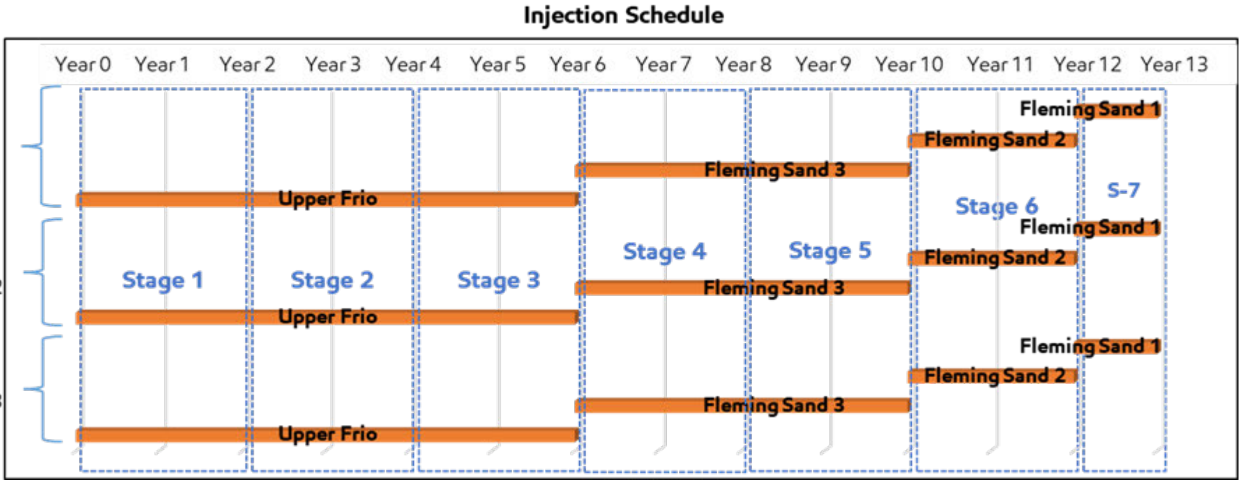

Table 7-1 provides the model-predicted maximum pressure differential and the change in injection pressures in each injection interval over time pursuant to 40 CFR 146.93(a)(2)(i). Figure 7-2 presents a graphical representation of the pressure differential data provided in Table 7-1

Table 7-1: Maximum Pressure Differential by Year for Injection Wells No. 01, No. 02, and No. 03 and the In-Zone Monitoring Well

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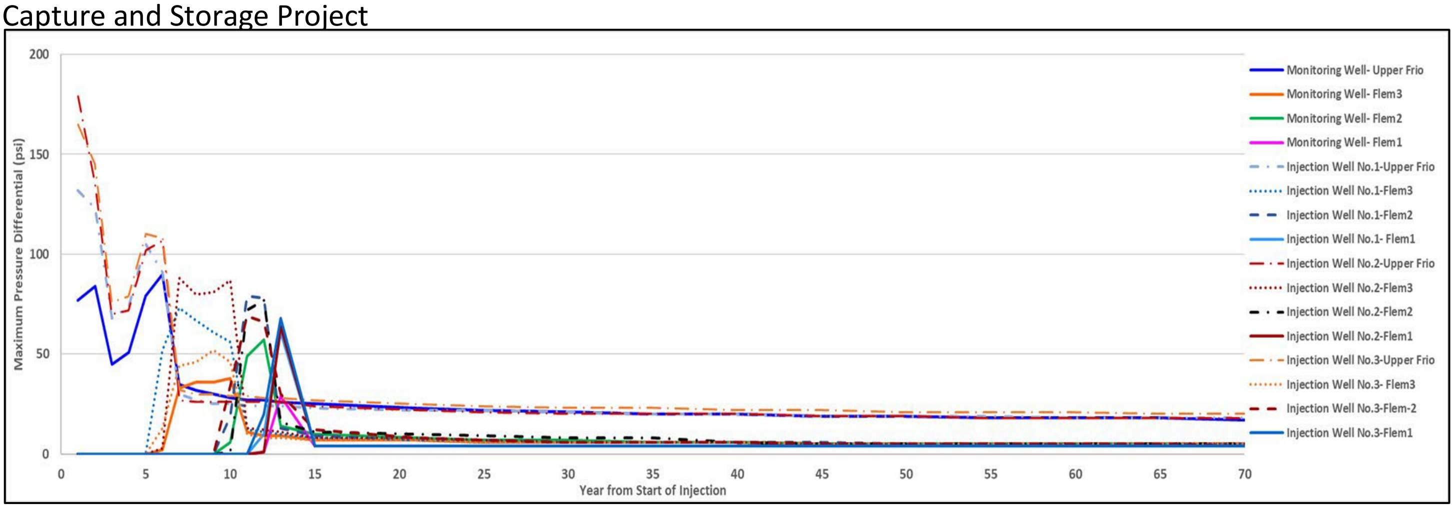
Figure 7-2: Maximum Pressure Differential Over Time for Injection Wells and Monitoring Well at Rose Carbon Capture and Storage Project

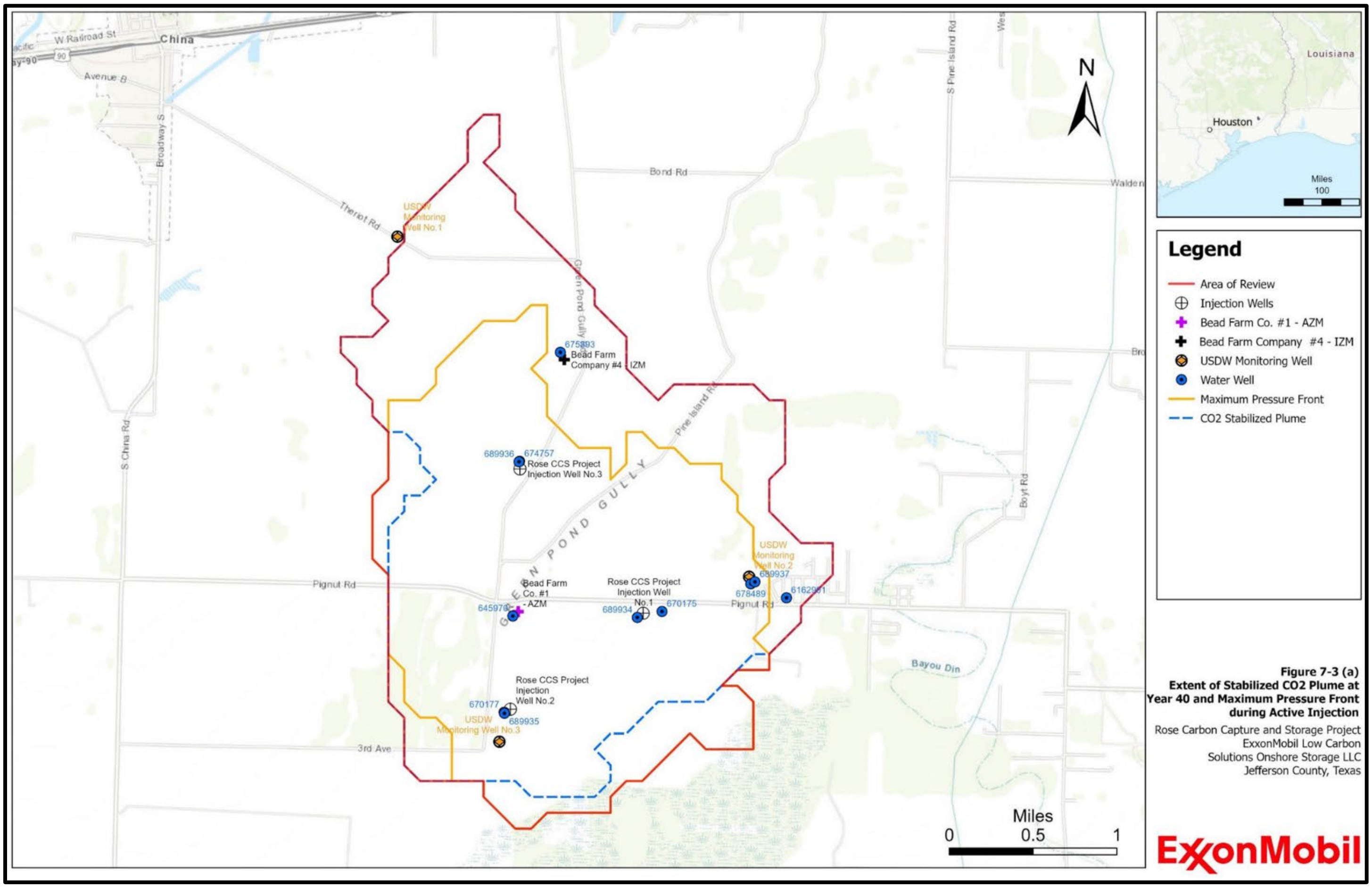


Predicted Position of the CO2 Plume and Pressure Front at Site Closure

Pursuant to 40 CFR 146.93(a)(2)(ii), the Area of Review (AoR) was delineated using computational modeling that accounts for all phases of CO2 (e.g., supercritical, dissolved, etc.) under proposed operational conditions. The AoR consists of both the CO2 plume and the extent of the pressure front. The following discussion provides the predicted evolution of both the CO2 plume and pressure front throughout the course of the 50-year PISC timeframe.

Figure 7-3a shows the extent of the AoR and its subcomponents at 40 years from start of injection (13 years of injection and 27 years from cessation of injection). Based on the model, the CO2 plume stabilization is predicted to occur 39 years after injection starts as described in Section 3.7.1 – Extent of CO2 Plume. Maximum pressure differentials occur during active injection phase and dissipate rapidly post-injection. These features are consistent with plume stabilization and protection of USDW. The CO2 plume at year 40 is indicated by the blue polygon, based on the maximum extent of any injection interval. The maximum extent of the pressure front is shown using the orange dashed line. This line represents a composite of the maximum extent of the pressure front at any point in time for the four injection intervals during all seven stages of injection operation. Note this maximum pressure front occurs during active injection (first 13 years). By year 40, the field pressure differential has fallen well below critical pressure in all zones.

Figure 7-3b provides an additional view of predicted CO2 plume at year 63 (50 years post- injection), compared to year 40 (27 years post-injection).



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Post-Injection Monitoring Plan

PISC monitoring is required by 40 CFR 146.93(b) to demonstrate that USDW is not endangered during the post-injection phase of the Project. Much like the operational phase, direct and indirect forms of monitoring will be used to track the evolution of the CO2 plume and pressure front after cessation of CO2 injection. The strategy for the Post-Injection Monitoring Plan is to rely on a core set of monitoring locations that were established during the operational phase of the Project. The following set of core monitoring locations were assumed to be installed and monitored pursuant to the Testing and Monitoring Plan and found sufficient pursuant to the AoR reevaluation process:

- In-Zone Monitoring at Injection Wells No. 01, No. 02, and No. 03 for indirect CO2 plume monitoring;
- In-Zone Monitoring Well No. 01 located updip from the injection wells for direct and indirect in-zone monitoring ;
- Above-Zone Monitoring Well (Bead Farm Co. #1; American Petroleum Institute 4224532908) located in the middle of injection wells for above-zone monitoring interval (AZMI) fluid sampling; and
- USDW Monitoring Wells No. 01, No. 02, and No. 03 for direct monitoring of USDW.

Figure 5-4 in Section 5 – Testing and Monitoring Plan illustrates the locations of these USDW monitoring wells. In the event that additional monitoring locations are added during the course of the injection operations under the direction of the UIC Program Manager, this core set of monitoring wells will be updated to reflect the detection monitoring system found sufficient for CO2 plume and pressure front migration evaluation at the close of the injection phase of the Project.

In accordance with 40 CFR 146.93(b)(1), monitoring of the pressure front and CO2 plume will occur for at least 50 years or an alternate duration approved by the UIC Program Director. ExxonMobil is proposing a schedule to submit PISC monitoring results annually and within 30 days of the anniversary date of injection cessation [40 CFR 146.93(a)(2)(iv)].

The following discussion provides details on the elements of the PISC monitoring strategy outlined above.

PISC and Site Closure Plan Reviews and Amendments

As required by 40 CFR 146.93(a)(3), ExxonMobil will submit an amended PISC and Site Closure Plan or demonstrate that no amendment is needed upon cessation of injection. Amendments to the plan, or the demonstration that no revisions are necessary, will be based on monitoring data collected during injection and the most-recent AoR delineation. The plume model will continue to be updated throughout the Project using monitoring information and the AoR reevaluation process and reporting requirements.

During PISC monitoring, ExxonMobil will conduct periodic reviews to incorporate new monitoring data, changes to the site computational model that may warrant changes in PISC monitoring, and/or changes in the methodology proposed to demonstrate non-endangerment of USDW. This approach will also support the use of new technologies that may be available in the future that facilitate a higher level of performance than the existing system. Pursuant to 40 CFR 146.84(e) and as described in Section 4 – Well Construction Plan and Operating Conditions, ExxonMobil will reevaluate the AoR periodically by comparing model predictions with monitoring results. Following an AoR reevaluation process, if the AoR and Corrective Action Plan are amended, ExxonMobil will review the PISC and Site Closure Plan to determine whether any updates are needed to ensure consistency across all plans. ExxonMobil may submit an amended PISC that describes how changes to the model affect predictions of pressure dissipation, plume migration rates, CO2 trapping, and additional processes that need to be accounted for in the non-endangerment demonstration.

In accordance with 40 CFR 146.93(a)(4), at any time during the life of the Project, ExxonMobil may modify and resubmit the PISC and Site Closure Plan for the UIC Program Director's approval within 30 days of such change.

Monitoring Above the UCCZ and USDW

During the injection phase, periodic monitoring of groundwater quality for significant geochemical changes above the UCCZ is required by 40 CFR 146.90(d) for the purpose of detecting potential leakage through the UCCZ. As described in Section 2 – Site Characterization, the UCCZ is a thick, muddy sequence that includes the Middle Miocene Amphistegina 'B' Shale a regionally continuous, transgressive marine shale. In accordance with 40 CFR 146.93(b)(1), groundwater quality and geochemical characteristics will be monitored in the

Above-Zone Monitoring Well (Bead Farm Co. #1) and in the USDW at USDW Monitoring Wells No. 01, No. 02, and No. 03 during the post-injection period.

ExxonMobil's strategy for monitoring groundwater above the UCCZ is a risk-based approach correlated to modeled CO_2 plume and injection zone characteristics. By the time the PISC monitoring program is initiated, the risk mitigating effects of injection sequence plan, the operating strategy, and corrective actions taken on artificial penetrations will likely have demonstrated protection of USDW throughout the operational phase of the Project. The list of analyses to be performed at these monitoring wells is summarized in Table 7-2 based on the same approach used for the operational phase of the Project.

Table 7-3 provides a summary of indirect monitoring technologies to be used for above-zone CO_2 plume and pressure front monitoring during the PISC phase of the Project. This monitoring strategy is consistent with the details and rationale provided in Section 5 – Testing and Monitoring Plan of this application. The results of the monitoring activities will be submitted in the annual report for the year in which they occur and within 30 days of the anniversary date of injection cessation or through an alternate agreed schedule with the UIC Program Director.

Table 7-2: Direct Above-Zone Monitoring and USDW Sampling and Analysis Program

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency [1]	Geochemical Analyses
USDW (Chicot Aquifer)	Water Level Gauging and Collection of Fluid Samples	USDW Monitoring Wells No. 01, No. 02, and No. 03	Annual	Total dissolved solids, alkalinity, electrical conductivity, temperature, pH, Gas composition (CO_2, CH_4, O_2, N_2), Dissolved cations (Ba, Cd, Ca, Cr, Co, Cu,
First Laterally Continuous	Collection of Fluid Samples	Above-Zone Monitoring Well	Annual	
Permeable Formation above UCCZ		(Bead Farm Co. #1)		Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn) Dissolved anions (HCO_3, $B(OH)_4$, Br, CO_3, Cl, F, I, NO_3, NO_2, PO_4, SO_4, S)

Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; F = fluorine; Fe = iron; HCO_3 = bicarbonate; Mg = magnesium; Mn = manganese; N_2 = Nitrogen; Na = sodium; O_2 = oxygen; SO_4 = sulfate

[1] The word "continuous" as used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected "continuously" will be averaged across a

reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.

Table 7-3: Indirect Above-Zone Monitoring Program

Testing/Monitoring Activity	Frequency	Reporting Schedule	Comment
Indirect Plume Monitoring by Time-Lapse Seismic Surveys or Equivalent Technologies	Survey Event #4 will occur at the end of operational period, a predicted total of 13 years after the start of operation. Contingent additional survey events during PISC phase to be determined based on the results from direct and indirect monitoring and model prediction.	Within 30 days after time-lapse seismic processing and interpretation has finished	The frequency and method of indirect plume monitoring will be determined in conjunction with the UIC Director

The analytical methods and quality assurance/quality control measures for collecting and analysis of fluid samples discussed in Section 5 – Testing and Monitoring Plan and will apply to the data collection program of the PISC, as appropriate.

In-Zone CO2 Plume and Pressure Front Tracking

ExxonMobil proposes to use direct and indirect methods to track the extent of the CO2 plume and pressure front in the injection zone during the PISC period. Direct monitoring in the injection zone includes continuous pressure and temperature measurements in the final injection zone for Injection Wells No. 01, No. 02, No. 03, and in In-Zone Monitoring Well No. 01. Indirect monitoring technologies include geophysical surveys to indirectly monitor subsurface conditions. By the start of the PISC phase of the Project, the direct and indirect monitoring activities will have been used for approximately 13 years and will be a proven set of monitoring technologies for detection monitoring of CO2 plume and brine crossflow potential.

Table 7-4 describes the proposed CO2 and pressure plume tracking methods for the PISC Plan. The water quality and geochemical parameters to be analyzed are presented in Table 7-5, consistent with Section 5 – Testing and Monitoring Plan where additional information on the monitoring methods described and how deviations would be identified.

Table 7-4: Direct and Indirect In-Zone Monitoring Program for PISC

Monitoring Element	Strategy
Time Period	Immediately following and for up to 50 years from cessation of injection operations.
Monitored Locations, Conditions, and Frequency	• Injection Wells No. 01, No. 02, and No. 03: continuous wellhead and borehole pressure at the 7th Stage injection interval and temperature in the injection zone. • In-Zone Monitoring Well No. 01: continuous pressure and temperature throughout the injection zone. • Above-Zone Monitoring Well (Bead Farm Co. #1): Annual AZMI fluid samples for water quality and geochemical parameters. • USDW Monitoring Wells No. 01, No. 02, No. 03: annual fluid samples for water quality and geochemical parameters. • Time-lapse seismic surveys or equivalent technologies for the AoR from surface to base of Upper Frio Sand 2. Survey Event #4 will occur at the end of operational period, a predicted total of 13 years after the start of operation. The need for additional surface seismic survey events during the PISC phase of the Project will be determined based on the results from direct and indirect monitoring and model prediction.
Planned Changes in Monitoring Techniques	None. The model-predicted rapid decrease in CO2 plume movement and pressure significantly reduces the potential for USDW endangerment following injection and eliminated need for additional monitoring.
Triggers	Table 3-21 in Section 3 – Area of Review and Corrective Action Plan provides a list of triggers for the AoR reevaluation process. Those triggers are applicable to the monitoring program.

Table 7-5: USDW and Above-Zone Monitoring Well Monitoring and Sampling Program During the PISC Phase

Monitoring Well	Frequency	Parameter/Analyte
Above-Zone Monitoring Well (Bead Farm Co. #1)	Annually	• Total dissolved solids
USDW Monitoring Wells No. 01, No. 02, No. 03	Annually	• Alkalinity • Electrical Conductivity • Temperature • pH • Gas composition (CO2, CH4, O2, N2) • Dissolved cations (Ba, Cd, Ca, Cr, Co, Cu, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn)

		• Dissolved anions (HCO_3, $B(OH)_4$, Br, CO_3, Cl, F, I, NO_3, NO_2, PO_4, SO_4, S)
Ba = barium; Br = bromine; Ca = calcium; CH_4 = methane; Cl = chlorine; F = fluorine; Fe = iron; HCO_3 = bicarbonate; Mg = magnesium; Mn = manganese; N_2 = nitrogen; Na = sodium; O_2 = oxygen; SO_4 = sulfate		

Submitting PISC Monitoring Results

In accordance with 40 CFR 146.93(a)(2)(iv), ExxonMobil will submit PISC monitoring data to the UIC Program Director in annual reports within 30 days following the anniversary of the date that injection ceases. The annual reports will contain information and data generated during the reporting period, such as:

- A list of monitoring events performed during the reporting period and the associated dates;
- A brief description of sampling/testing/analytical locations, elevations/depths, equipment, and procedures, indicating whether (and why) departures from the procedures specified in the PISC and Site Closure Plan occurred;
- Changes to the monitoring program that took place during the reporting period (e.g., repair to monitoring wells, implementation of approved changes in the frequency of monitoring activities based on criteria established in the PISC and Site Closure Plan and approval of UIC Program Director);
- Synthesis and interpretation of the results that describe trends in parameter values or lack of trends, statistical tests performed, alignment between actual and plume model predictions, the appearance of anomalous or unexpected results, and progress toward attaining the EPA and Railroad Commission of Texas (RRC) criteria for non-endangerment;
- Map(s) and cross section(s) showing the AoR, monitoring locations, and the interpreted extent of the separate-phase CO_2 plume and the pressure front; and
- Any recommended changes to the PISC and Site Closure Plan to continue protection of USDWs.

Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization and in accordance with 40 CFR 146.93(b)(2) and 40 CFR 146.93(b)(3), ExxonMobil will provide documentation to assess the potential for USDW to be at risk of endangerment from the CO_2 plume at the end of the PISC phase of the Project. The non-endangerment demonstration will be based on monitoring data and a demonstration that the structure of the confining zones, combined with the geochemical conditions of the subsurface, have effectively permanently sequestered the stored CO_2. This information will be used to demonstrate that additional monitoring is not needed to protect USDW and the Project has met the compliance obligations to receiving authorization for site closure.

This demonstration will be in the form of a detailed report submitted to the UIC Program Director that synthesizes site- and Project-specific information and demonstrates a current understanding of system behavior at the time of the non-endangerment demonstration. The following subsections outline the type of information to be presented in the non-endangerment demonstration report.

ExxonMobil will engage the UIC Program Director as soon as the available data are aligned with the criteria for site closure, which may ultimately be less than the default PISC duration of 50 years pursuant to 40 CFR 146.93(b)(2) and 40 CFR 146.93(c).

Introduction and Overview for Non-Endangerment Demonstration

A summary of relevant background information will be provided in the introduction section, including the operational history of the injection Project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

Summary of Existing Monitoring Data

The monitoring data collected throughout the Project's lifecycle will be summarized and used to describe how the UCCZ functioned as a barrier to mitigate endangerment of USDW and how the CO2 is effectively trapped in the injection zones. The non-endangerment demonstration will include a summary of previous monitoring data collected at the site, pursuant to the details in Section 4 – Well Construction Plan and Operating Conditions, and Section 5 – Testing and Monitoring Plan of this application as well as the PISC and Site Closure Plan. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)] and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of the monitoring infrastructure that has existed at the site. The data will be compared with baseline data collected during site characterization, including the use of statistical analyses as warranted [40 CFR 146.82(a)(6) and 146.87(d)(3)] to assess trends in key parameters that support the proposal for site closure.

Summary of Computational Modeling History

A series of data sources detailed in Section 5 – Testing and Monitoring Plan of this application will be used to update the computational model at least once every five years, more frequently if warranted. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- In-zone temperature and pressure data;
- Injection rate and volume data;
- CO2 plume location based on indirect geophysical monitoring; and
- AZMI data regarding the performance of the UCCZ.

The procedure used to reevaluate the AoR will be based upon the data collected between reevaluations and the well conditions at the time of reevaluation. The post-injection data will include historical injection rates, pressures, pressure fall-off, and historical operational parameters of the three injection wells. ExxonMobil will rely on a process of history matching the plume model results with the actual monitoring data. The measured data will be used as a calibration point for the plume model and the input parameters adjusted to provide a reasonable match between the two data sets. Through this or a similar process, ExxonMobil will provide a validation of the model performance for the CO2 plume and pressure front.

Evaluation of Reservoir Pressure

The non-endangerment demonstration will include an evaluation of the residual pressure and the potential for future endangerment of USDW continued trends in pressure dissipation.
Information will be provided to describe how the pressure and buoyancy effects on plume and pressure migration decayed over time and how the residual levels comply with the requirements for non-endangerment. This evaluation will consider the most-recent AoR delineation/modeling results and pressure monitoring data. The same model that supported the delineation of the AoR or similar approved model by UIC Program Manager will be used for this modeling as it will be verified (or calibrated) by actual monitoring and operational data via AoR reevaluations.

Evaluation of the CO2 Plume

The evaluation of the CO2 plume will evaluate the characteristics of the gas-phase CO2 plume, the aqueous-phase CO2 plume, and the dissolved-phase CO2 plume, as appropriate. The evaluation of the potential CO2 plumes will rely on monitoring data including geochemical and geophysical analyses and the most-recent AoR modeling results. Direct measurements of temperature and pressure of CO2 in the injection zone as well as the results of geophysical measurements will be used to confirm plume location and demonstrate plume migration rates. A comparison of monitoring data with the most-recent modeling results will also be used to corroborate model predictions of the phase-state of CO2 and the degree and processes of CO2 trapping over time.

Evaluation of Emergencies or Other Events

A key feature of the AoR is how few artificial penetrations were identified and of those, only two penetrated the UCCZ. The artificial penetration of the UCCZ will be re-entered, and a corrosion resistant cement plug will be placed to restore the integrity of the UCCZ, and additional cement plugs will be set to protect USDW from crossflow potential. If any subsequent artificial penetrations are discovered to have a potential to threaten USDW, they will have been remediated using the same procedures such that no artificial penetrations of concern remain at the time of site closure.

The data and evaluation methods specified pursuant to the requirements of Section 5 – Testing and Monitoring Plan as well as the PISC Plan provide the basis for demonstrating that no future endangerment of USDW is likely to occur.

Site Closure Plan

ExxonMobil will conduct site closure activities to meet the requirements of 40 CFR 146.93(d) through (h) as described below. ExxonMobil will submit a final Site Closure Plan and notify the UIC Program Director at least 120 days prior of its intent to close the site. Once the UIC Program Director has approved closure of the site, ExxonMobil will plug all injection and monitoring wells and submit a site closure report to the EPA and RRC. The activities, as described below, represent the planned activities based on information provided to EPA. The actual Site Closure Plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site. Additionally, ExxonMobil will record a notation on the deed to the site that the land has been used to sequester CO2.

Site closure activities will also include removing all surface equipment and restoring the site to its prior land surface condition.

Pre-Closure

In accordance with 40 CFR 146.93(d), a notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

The site closure notice submitted to the UIC Program Director will include the following:

- Facility information, name, and location;
- A list of contact personnel for allowing timely direct communication to resolve any pressing issues; and
- A projected closure date, no less than 120 days following the site closure notification submission, unless the UIC Program Director has approved a different period prior to notice submission.

Plugging Activities

Injection Wells No. 01, No. 02, and No. 03 will be plugged as discussed in Section 6 – Injection Well Plugging Plan. After injection in the injection wells ceases and after the appropriate post- injection monitoring period is complete, the monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR 146.92 and in compliance with applicable state requirements. The plugging procedure and materials will be designed to mitigate fluid movement and protect USDW. Prior to plugging the wells, the necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plans will be submitted to the UIC Program Director no later than 60 days prior to plugging of the wells.

Following receipt of the approved plugging plans, wells below the lowermost USDW and above the UCCZ will be logged and pressure tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The casing in these wells will be closed in place and it will not be retrieved at abandonment. A combination of permanent packers with plugs and cement on top and cement plugs will be set to plug the wells. All casing strings will be cut at least three feet below ground level. A steel plate, with the required permit information, will be welded to the top of the casing, to the extent required by State of Texas requirements.

Site Restoration

Once the injection and monitoring wells are plugged and abandoned, the surface equipment will be decommissioned and removed from the well site. The well site will be restored to a condition agreed upon with the landowner.

Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Program Director per the requirements of 40 CFR 146.93(f) and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats [40 CFR 146.93(f)(1)];
- The survey plat will indicate the locations of the injection wells relative to permanently surveyed benchmarks and will include the location(s) of the monitoring well(s);
- Documentation of well-plugging report will be filed with the RRC [40 CFR 146.93(f)(2)];
- Post-injection monitoring records will be summarized; and
- Records of the nature, composition, and volume of the CO2 stream for the injection period will be summarized [40 CFR 146.93(f)(3)].

Pursuant to 40 CFR 146.93(g), a record of notation in the Project facilities and infrastructure will be filed on the property deed to provide notice to landowners of the following:

- The land use to sequester CO2;
- The name of the state agency with which the survey plat was filed (RRC) and the EPA Regional Office (Region VI) at which it was submitted; and
- The total volume of CO2 injected, the injection zones into which it was injected, and the period over which injection occurred.

As required by 40 CFR 146.93(h), ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Program Director for retention at a location designated by the UIC Director for that purpose.

ATTACHMENT 9: EMERGENCY AND REMEDIAL RESPONSE PLAN

Facility Information

Facility name: Rose Carbon Capture and Storage Project
Rose CCS Nos. 1, 2, and 3 wells

Well location: Jefferson County, Texas

Well Name and Number	*API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	*District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	*District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	*District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
(*) - Railroad Commission of Texas				

Emergency and Remedial Response Plan

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting this Underground Injection Control (UIC) Class VI Permit to Convert Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a maximum of 5 million metric tonnes per annum of carbon dioxide (CO_2) using three injection wells over an injection period of up to 13 years. The predicted total CO_2 storage is 53 million metric tonnes. This Emergency and Remedial Response Plan (ERRP) is submitted in compliance with the requirements of the Code of Federal Regulations, Title 40, Section 146.94 [40 CFR 146.94]. Under 40 CFR 146.90(g), the actions described in the ERRP are to be implemented immediately to address an event where the movement of the injection fluid or formation fluid endangers underground sources of drinking water (USDW). ExxonMobil prepared this ERRP to provide both the scope of actions to be taken and the schedule under which the actions would be implemented.

ExxonMobil has already created a number of engineering design and planning safeguards to reduce the potential for the occurrence of an emergency and remedial response event. These steps are based on ExxonMobil's global experience and expertise with risk management in site selection, well drilling and completion, and reservoir operations. The risk management approach is evident in the preparation of sections of this UIC Application. Section 2 – Site Characterization describes how the geologic setting is favorable to safe CO_2 sequestration because of the favorable injection zone and confining zone characteristics that exist at the site. Section 3 – Area of Review and Corrective Action describes how the CO_2 plume and pressure front are predicted to be confined to the injection zone and how pressure will be managed to reduce the potential for leakage to USDWs. Two artificial penetrations through the confining zones will be remediated appropriately to safeguard USDWs within the Area of Review (AoR) before operations commence. Section 4 – Well Construction Plan and Operating Conditions describes how the well design process and operating controls for mechanical integrity and pressure control to maintain a high level of risk reduction for the Project. Lastly, Section 5 – Testing and Monitoring Plan, provides the data acquisition plan for tracking the CO2 plume and brine pressure front to assess compliance with control and containment requirements.

The purpose of this section is to provide the elements of the risk management process undertaken for the Project so that the UIC Program Director can ultimately approve the remedial and response actions in advance. Once approved, ExxonMobil will be prepared to implement the actions necessary to facilitate and expedite response efforts for the possibility of a leak occurring from the injection zone. The ERRP will apply over the life of the Project, including throughout the post-injection site care period [40 CFR 146.94(a)].

Objectives

The ERRP identifies a set of hypothetical potential risk scenarios under which there may be an endangerment to USDWs and the actions to be taken to mitigate such risk. The objectives of the ERRP are aligned with the requirements of 40 CFR 146.94, which include:

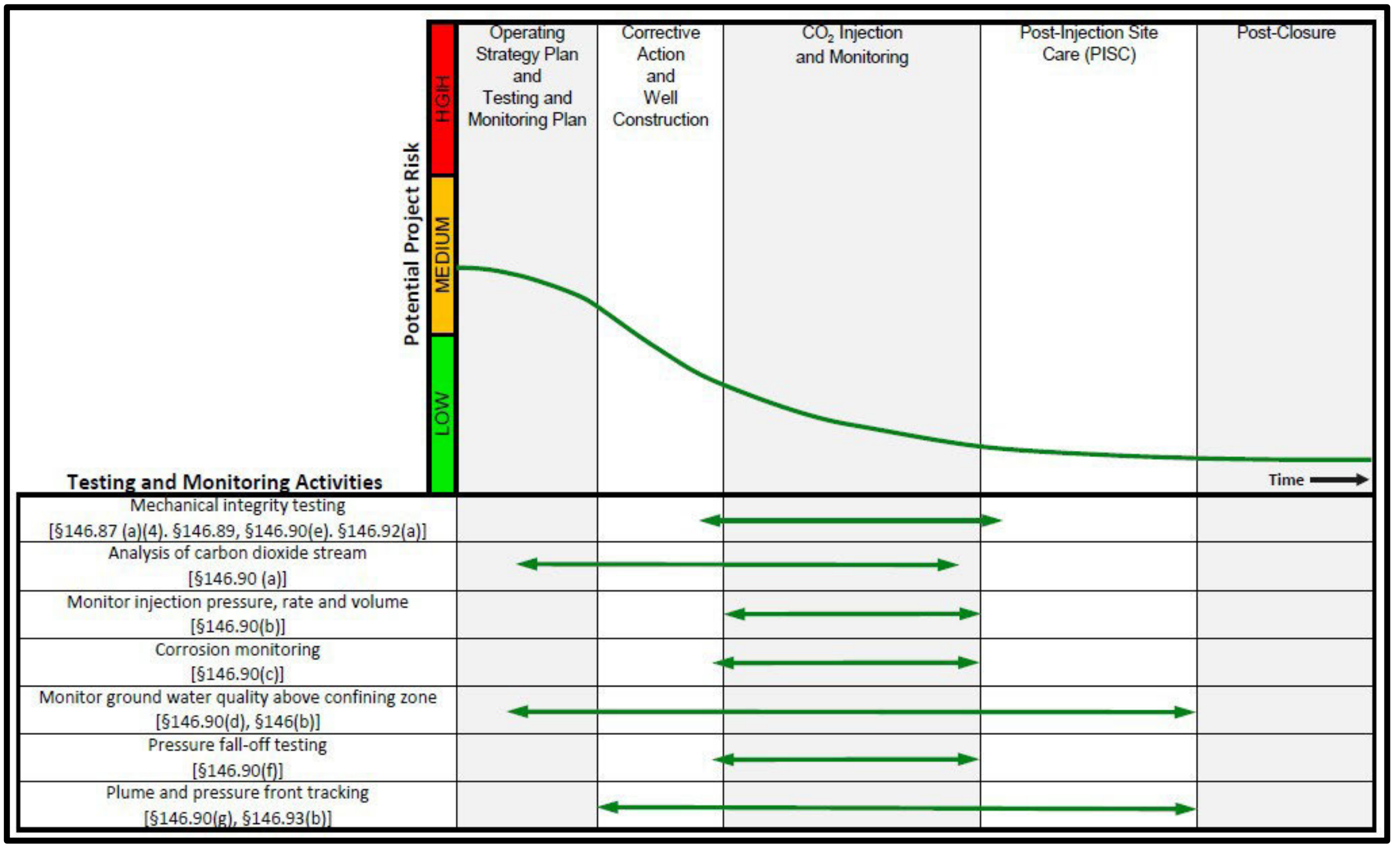
- Identify potential risk scenarios and adverse events that could impact USDW in the AoR. The assessment focuses on those events that were found to have a combined probability and consequence that makes them more likely to have an impact than other factors.
- Provide a description of the response actions necessary to reduce the potential consequences to USDWs. For each scenario considered to be of material concern, describe the anticipated severity of the event, the phase during which the event could occur (i.e., construction, injection and/or post-injection phases), the proposed avoidance measures, what methods will detect the loss of containment or control, the response actions, notification requirements, and personnel and equipment that would be employed to mitigate the risk; and
- Provide contact information for response personnel, a communications plan, and a description of staff training and exercise procedures.

Overview of Risk Management Process

ExxonMobil took the findings from the site characterization, AoR, and corrective action sections of the Application and identified hypothetical risk scenarios that could pose a potential threat to USDWs in the event of occurrence. ExxonMobil's risk assessment process was used to estimate the probability and consequence of each risk scenario based on the experience and judgment of the risk subject matter experts for the Project. The list was sorted from the most probable and consequential risk scenario to the least probable and consequential scenarios so that the critical scenarios and the response actions to be undertaken could be identified.

As shown in Figure 8-1 below, the maximum anticipated risk level for the Project, including the combination of the selected risk scenarios for the ERRP, is within the medium risk category. As mentioned above, several risk management steps were already taken to address the potential for CO2 or brine migration to occur.

Figure 8-1: Summary of the Risk Assessment Process for the Lifecycle of the Project



As shown in Figure 8-1, potential risk is at its maximum during the initial investigation and characterization of the Project site because artificial penetrations, fractures, and faults were identified in the confining zone. The potential for these features in the upper composite confining zone (UCCZ) to become a migration pathway for a release of CO2 were mitigated by planning for the following actions described in the Application:

- Artificial penetrations through the UCCZ will be re-abandoned to restore containment integrity at each artificial penetration location where the potential for elevated crossflow risk was identified;

- The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault to mitigate the potential for CO2/brine leaks through seal(s) due to mechanical fracturing or migration of CO2/brine along faults;

- State-of-the-art injection well and monitoring well construction methods and mechanical integrity testing (MIT) will be employed to reduce the potential for the loss of internal or external mechanical integrity, which could potentially release CO2 to USDWs or the atmosphere;

- The composition of the injectate stream will be managed and monitored such that unexpected reactions with the potential to impact containment are mitigated;

- CO_2 plume and pressure front tracking will be undertaken using a combination of direct and indirect measurements and reported semiannual for review and consideration in AoR reevaluations, at a minimum frequency of every five years; and

- The predictive reservoir modeling will be calibrated and verified using monitoring data to identify the potential for the CO_2 plume and pressure front to encounter artificial penetrations that have the potential for CO_2 or brine crossflow from the injection intervals to the lowermost USDW and take preventive measures before such an event could occur.

Identification of Resources/Infrastructure in Area of Review

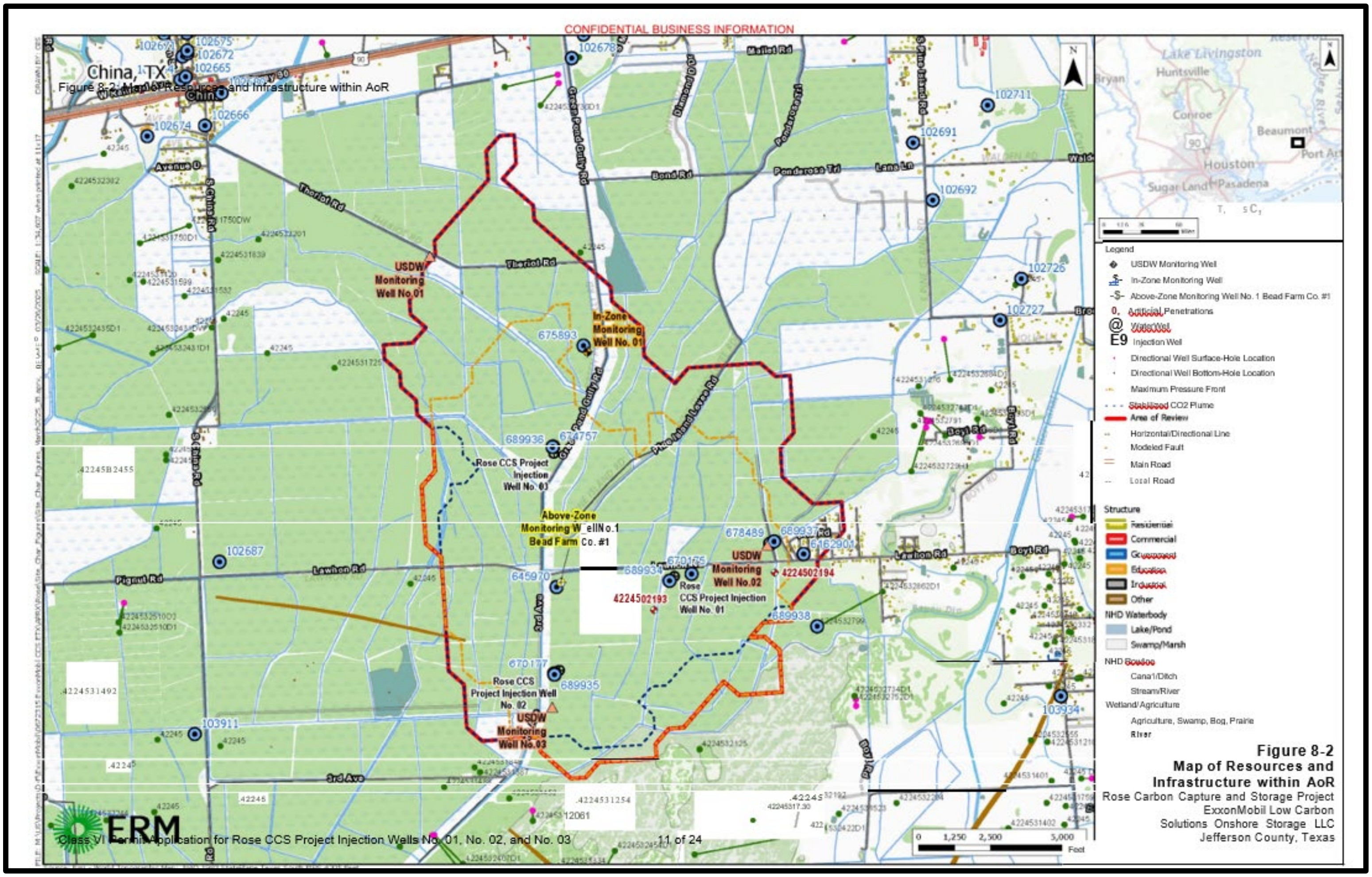
Figure 8-2 provides an illustration of the land use within and surrounding the AoR. As shown, the land use and resources/infrastructure are primarily related to oil and gas exploration and production, agricultural crop production, and undeveloped rural acreage with some residential development. The infrastructure development is primarily in the form of county roads and power transmission lines to service the few developed areas.

The water resources in the vicinity of the Project that may be affected by a CO_2 or brine leakage event that could endanger USDW include water wells completed in the Chicot and Evangeline Aquifers CBI CBI [redacted]

A total of two water wells were reported to be present within the AoR. A plugged/destroyed water well (State Well Number 6162901) was reportedly located 1.5 miles east of Injection Well No. 01. Another in-use water well (State Well Number 645970) is collocated at the Bead Farm Co. #1 well pad.

As shown on Figure 8-2, one water conveyance canal was identified as Green Pond Gully. Bayou Din is also located along the southern limit of the AoR.

A total of two oil and gas wells were identified within the AoR, and both were reported as plugged and abandoned in the available records from the Railroad Commission of Texas. The stratigraphic well drilled by ExxonMobil is also located within the AoR. Beyond the AoR, the City of Beaumont, Texas, is located more than five miles northeast of the AoR boundary and the Town of China, Texas, is located approximately one mile northwest of the AoR boundary.



Identification of Risk Scenarios of Interest

Through the risk assessment process, the following list of scenarios were considered of sufficient probability and consequence to warrant development of response action plans. Other scenarios were considered but were found to have relatively low probability and consequence factors and thus do not warrant further consideration at this time. As shown below, a total of nine risk scenarios were considered for the ERRP.

Table 8-1: Hypothetical Risk Scenarios for ERRP

CO2 and Brine Containment or Control Feature of Interest	Hypothetical Release Mechanism associated with Risk Scenario
1. Mechanical Integrity of Injection Well Casing or Cement Seal	1a. CO2 release arising from injection well cement degradation or annular space defects in cement completion.
	1b. CO2 or brine leaks to USDW at injection well because of cement degradation or annular space defects in cement completion.

2. Artificial Penetrations of UCCZ	2a. CO2/brine crossflow to USDW at legacy well in AoR with lack of casing or cement integrity issues.
	2b. CO2 release detected at a legacy well because of loss of casing or cement mechanical integrity, implying a release has occurred that may endanger USDWs.
3. Mechanical Integrity of Operating Equipment	Pressure gauge malfunction or shut-off valve malfunction results in an uncontrolled pressure situation and CO2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.
4. Natural Features Affecting Sealing Properties of UCCZ	4a. CO2/brine leaks through an existing fault or fracture through UCCZ within the AoR impacting a USDW.
	4b. Lateral egression of CO2/brine below primary seal, beyond AoR, and release to USDW via unknown fracture or fault.
	4c. Induced or natural seismic event creates or enhances the transmissivity of faults or fractures in the UCCZ, resulting in an increased potential for CO2 or brine migration along the pathways toward USDWs.
	4d. Induced or natural seismic event occurs creates or enhances mechanical integrity deficiency in the cement and plug of an artificial penetration, resulting in an increased potential for CO2 or brine migration along the pathways toward USDWs.

Use of Severity to Define Scope of Response Action

Response actions were developed for each of the nine hypothetical risk scenarios identified for the ERRP. As listed in Table 8-2, the severity of the risk scenario was fit to a three-tiered categorization of emergency conditions. In addition, the response actions envision a stage-gate process where the information regarding the degree of severity for the emergency condition is evaluated to align the appropriate level of response to bring about mitigation of the emergency event.

Table 8-2: Degrees of Risk for Emergency Events

Emergency Condition	Definition

Major emergency	Events pose immediate substantial risk to USDWs and indirectly from USDW endangerment to resources or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) must be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to USDW and indirectly from USDW endangerment to resource or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to USDW, resources, or infrastructure.

In accordance with 40 CFR 146.94(b), for the events below, if the injected CO2 stream and associated brine pressure front may cause an endangerment to a USDW, each set of response actions start with immediately ceasing injection and notifying the UIC Program Director within 24 hours of the confirmation of a release event and the intention to implement the appropriate response action in the ERRP.

Response Plans for Risk Scenarios

The following response action details are provided to have a pre-approved set of actions in place should measurements collected pursuant to the Section 5 – Testing and Monitoring Plan indicate a malfunction or deviation from permitted limits.

Integrity of Injection Well Casing or Cement Seal

Two hypothetical release mechanisms were identified for injection wells that could possibly result in a release of CO2 and/or brine to USDWs. CO2 could be detected at an injection well, implying that internal or external mechanical integrity of an injection well may have been compromised and released CO2 to USDWs. CO2 or brine could also be released to USDW at the injection well because of subsurface cement degradation or annular space defects in cement completion.

Hypothetical Release Mechanism: mechanical integrity failure at injection well resulting in release of CO2 and/or CO2 and/or brine to USDWs.
Severity:
• Minor: A malfunction in the monitoring equipment created a false positive indication of a release when in fact none occurred. Alternatively, detection monitoring equipment at the wellhead facility detects the release and the well was shut-in, representing a minor CO2 release.
• Serious: A failed MIT identified a release mechanism, but detection of brine or CO2 was not apparent in the detection monitoring system.
• Major: A detection of CO2 and/or brine to USDW within the AoR prior to confirming the source of the injection well release point.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:

• Proper wellbore design, including the use of corrosion resistant cement and CO_2 compatible metallurgy of the casing and tubing, will be used for construction of the injection well.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Deficiency identified during continuous pressure and temperature monitoring, pressure falloff tests, and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO_2 plume and pressure tracking above UCCZ indicates a change in conditions.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• MIT identifies a potential issue in the integrity of the well.
• Well casing and cement bond logs conducted during shut-ins to assess loss decay or corrosion more than acceptable limits.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.
○ The Site Manager will respond to the event for an initial assessment to determine severity of event.
• Minor Event:
○ Close the wellhead valve to shut-in well. Perform investigation. If the investigation shows a false positive, reopen the valve and continue operations.
○ If there is a loss of containment, vent CO_2 from surface facilities.
○ Monitor well and annulus pressures.
○ Collect fluid samples from detection monitoring well network to compare water quality and geochemical parameter concentrations with baseline conditions.
○ If there is a loss of containment, implement mitigation strategy for remedial actions with consultation of UIC Program Director.
• Serious or Major Event:
○ Close wellhead valve to shut-in well.
○ If appropriate, vent CO_2 from surface facilities.
○ Engage with ExxonMobil emergency response team to ensure that any necessary and appropriate notifications to local authorities are made and if additional emergency actions are necessary.
○ Monitor well head for CO_2 and casing and annulus pressures.
○ Identify and implement remedial actions to repair damage to well. Repairs will be conducted with UIC Program Director approval and guidance.

○ Collect fluid samples from detection monitoring wells and compare results with baseline and acceptable health-based concentration thresholds. If exceedances, consultation of the UIC Program Direct on expansion of detection monitoring program and need for interim response actions.
○ Implement additional groundwater monitoring as required by UIC Program Director to define extent and magnitude of release.
○ If health-based concentrations are exceeded, notify UIC Program Director of exceedances for determination of the need for USDW remediation.
○ If health-based concentrations are exceeded in the vicinity of water wells, coordinate with the UIC Program Director to provide an alternate potable water supply.
○ Continue USDW remediation program and compliance monitoring based on UIC Program Director requirements until a determination of no further action is obtained from UIC Program Director.
○ Once a no further action determination has been obtained from UIC Program Director, conduct MIT for confirmatory indications that the well integrity has been restored.
○ With the UIC Program Director's approval, develop a plan for re-initiating the injection well.
○ Demonstrate mechanical integrity.
○ Seek permit authorization from UIC Program Director for resuming injection.
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

Integrity of Injection Well Casing or Cement Seal for Legacy Wells

Consistent with the potential for CO2 or brine to migrate to USDW at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may provide a similar risk scenario. Legacy wells were identified within the AoR that penetrate the UCCZ. The plugging of legacy wells will be completed as a corrective action prior to operation. The objective of this risk scenario is to provide the response actions in the event that unknown legacy wells are found and suspected of CO2 and/or brine leakage to USDWs as a result of potential casing or cement integrity issues in the AoR.

Hypothetical Release Mechanism: CO2 and/or brine migrate to USDW at an artificial penetration as detected within the AoR.
Severity:

• Minor: direct and indirect CO_2 plume and pressure front tracking indicate that the legacy well is in the path of migration with the potential to create elevated pressures and a potential for corrosive environment to be created at the well location.
• Serious: direct and indirect CO_2 plume and pressure front tracking indicate that the legacy well has been impacted with minor increases of CO_2 and/or brine pressures and corrosive fluids.
• Major: direct and indirect CO_2 plume and pressure front tracking indicate that the legacy well has been impacted by pressures that could create a crossflow potential between the injection zone and USDW if a conduit were present.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO_2 plume and brine tracking systems.
• Plume model updates to predict pressure front arrival times at legacy well locations and adjust timing of phased-corrective action.
Detection methods:
• CO_2 plume and pressure tracking indicates impact is likely.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• Well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.
Response actions:
For minor severity: enhancing CO_2 plume and pressure front tracking data collection program and update plume model calibration with additional data points, as appropriate. Confirm migration pathways and adjust operating conditions to reduce the potential to impact legacy well and increase data monitoring frequency to confirm potential impacts.
For major and serious events:
• Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
• Determine the severity of the event, based on the information available, within 24 hours of notification.
• Initiate shutdown plan in accordance with well permit.
• Notify emergency contacts.
• Conduct testing and monitoring at legacy wellhead to assess mechanical integrity and potential points of mechanical failure.
• Assess location and degree of CO_2 movement, as described in Section 5 – Testing and Monitoring Plan.

• If the presence of CO_2 or brine crossflow is likely, develop (in consultation with the UIC Program Director) a case-specific work plan to install additional groundwater monitoring points near the affected legacy well to assess potential for migration above the UCCZ and into USDW, delineate impact if found.
• Compare fluid sample concentrations with risk-based human health thresholds to identify whether an exceedance of acceptable limits has occurred.
• If so, prepare a remedial plan for UIC Program Director review and approval.
• Recomplete legacy well plugging to restore the integrity of cement plugs at UCCZ and base of USDW.
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge malfunction or other similar equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2/brine crossflow to USDW by fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Severity:
• Minor: Failure of monitoring equipment to document compliance with permit operating conditions, but subsequent evaluation of available information demonstrates that well integrity has not been impacted.
• Serious/Major: Failure of monitoring equipment to document permit operating conditions and subsequent evaluation of the data documents non-compliance with permitted operating conditions and potential for well integrity impacts.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturers recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to confirm compliance with permitted operating conditions.

Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.
○ The Site Manager will respond to the event for an initial assessment to determine severity of event.
• Notify the UIC Director within 24 hours per 40 CFR 146.91(c).
• Determine the cause and severity of failure to determine if the CO2 stream or formation fluids may have been released into any unauthorized zone.
• For a Minor emergency (sensor or monitoring failure):
○ Conduct assessment to determine whether there has been a loss of mechanical integrity.
○ If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
○ Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
○ Contact security to restrict access to the storage site.
○ Vent CO2 from surface facilities.
○ Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
○ Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
• For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time [i.e., >48 hours] and/or well intervention to remediate):
• Contact security to restrict access to the storage site.
• Communicate with ExxonMobil personnel and local authorities to isolate the area and initiate evacuation plans, if necessary.
• Initiate shutdown plan and shut-in injection well and vent CO2 from surface facilities.
• Manually collect surface tubing pressure and annulus pressure as needed to monitor the well until monitoring equipment is repaired.
• Collect fluid samples from detection monitoring wells and compare results with baseline and acceptable health-based concentration thresholds. If exceedances, consultation of the UIC
• Program Direct on expansion of detection monitoring program and need for interim response actions.
• Implement additional groundwater monitoring as required by UIC Program Director to define extent and magnitude of release.
• If health-based concentrations are exceeded, notify UIC Program Director of exceedances for determination of the need for USDW remediation.
• If health-based concentrations are exceeded in the vicinity of water wells, coordinate with the UIC Program Director to provide an alternate potable water supply.

• Continue USDW remediation program and compliance monitoring based on UIC Program Director requirements until a determination of no further action is obtained from UIC Program Director.
• Once a no further action determination has been obtained from UIC Program Director, conduct MIT for confirmatory indications that the well integrity has been restored.
• With the UIC Program Director's approval, develop a plan for re-initiating the injection well.
• Demonstrate mechanical integrity.
• Seek permit authorization from UIC Program Director to resume injection under permit authorization.
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.

Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDW. For example, CO2 could hypothetically leak through natural faults or fractures in the UCCZ within or beyond the AoR and impact USDWs. CO2 or brine could hypothetically migrate horizontally to artificial penetrations within or beyond the AoR that are not sealed at the UCCZ and result in a release to USDWs. Response actions were developed to address such scenarios in the event that they occur.

The primary limiting factor for the magnitude of the release for these scenarios was based on the site characteristics described in Section 2 – Site Characterization. CO2 and brine leaks through shales due to mechanical fracturing were not considered a material concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately 3,000 feet of saturated shale, mudstone, and sand. Such a release would likely be detected by the detection monitoring program for groundwater prior to release to the surface. Therefore, ambient air monitoring in the AoR was contingent on the confirmed release of CO2 to USDW at sufficient concentrations to migrate to the surface at levels above health-based thresholds.

The following response actions were developed to mitigate the potential for releases through the UCCZ, which were assumed to occur during injection operations and/or post-injection site care.

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDWs.
Severity:
• Minor: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture is in the path of migration with the potential to create elevated pressures sufficient to cause crossflow above the UCCZ.

• Serious/Major: direct and indirect CO_2 plume and pressure front tracking indicate that a fault or fracture has been impacted by pressures that will likely create a crossflow potential between the injection zone and USDW. For faults and fractures, the threshold pressure is based on fault-slip potential (Section 2.11).
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO_2 plume and brine tracking systems.
• Plume model updates to predict pressure front arrival times at fault and fracture locations and adjust timing of phased detection monitoring programs elements.
Detection methods:
• CO_2 plume and pressure tracking indicates impact is likely.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data confirm impact to fault, fracture, or artificial penetration outside of AoR.
Response actions:
• If the detection monitoring program outline in the Section 5 – Testing and Monitoring Plan or similar third-party monitoring program detects a potential release of CO_2 or brine through the UCCZ to the first water-bearing zone above the UCCZ or USDW, notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
• Determine the severity of the event, based on the information available, within 24 hours of notification.
• For all emergencies (Major, Serious, or Minor):
○ Initiate shutdown plan.
○ Notify emergency contacts.
○ Implement an ambient air monitoring program in the vicinity of the CO_2 plume in groundwater and the release mechanism.
○ Conduct a Vertical Seismic Profile to assess location and degree of CO_2 movement, as described in Section 5 – Testing and Monitoring Plan.
○ If the presence of CO_2 above the UCCZ is likely, develop (in consultation with the UIC Program Director) a case-specific work plan to install additional groundwater monitoring points to assess the extent of CO_2 and brine migration above the UCCZ and into USDW.
○ Compare fluid sample concentrations with risk-based human health thresholds to identify whether or not an exceedance of acceptable limits has occurred in groundwater and evaluate the potential for cross-media transport to other environmental media.
○ If unacceptable concentrations are apparent, prepare remedial plan for UIC Program Director review and approval.
○ Use the water well survey provided in Section 5 – Testing and Monitoring Plan to determine if potable water wells are located in the vicinity of the affected groundwater that could potentially become impacted from the release.

◦ If so, coordinate with the UIC Program Director to provide potable water to water well owners.
◦ Continue remedial efforts to achieve a no further action determination from the UIC Program Director.
◦ Seek permit authorization from UIC Program Director to resume injection under permit authorization.
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.

Induced or Natural Seismic Event

Natural or induced seismic events of sufficient magnitude to create damage were found to be improbable for the site location and under permitted operating conditions that are below the critical fracture pressure. In the chance that such seismic conditions occurred, the consequences could be of significance regarding the integrity of the artificial penetrations of the UCCZ and the natural faults and fractures. Therefore, the following response actions were developed to gather information regarding the potential for CO2 and brine confinement issues to arise under such events.

ExxonMobil will rely upon U.S. Geologic Survey seismic monitoring data for the site and surrounding area to provide information on a seismic event, should one occur. If a review of the data indicates that the event was more likely than not associated with the injection zone in or near the AoR, ExxonMobil will notify the UIC Program Director of the intent to install a site- specific network of seismic stations to provide additional information with the regional seismic data. The details of the site-specific seismic monitoring system will be provided to the UIC Program Director as a modification of Section 5 – Testing and Monitoring Plan. Table 8-3 provides the response actions depending on severity of the seismic event.

Table 8-3: Response Actions for Seismic Events

Threshold Condition[1]	Response Action for Epicenter Within a 100-Square Mile Area (5.6-Mile Radius) of an Injection Well[2]
Seismic event above M2.0 and below M3.0	• Monitor well pressure, temperature, and annulus pressure to assess if well operation within permitted status and assess the potential for mechanical integrity issues to have occurred from the seismic event. Otherwise, continue normal operation within permitted levels and review seismic data. • Reporting findings to the UIC Program Director as appropriate

Seismic event >M3.0	• Communicate with facility personnel and local authorities about the operating condition of the injection wells and initiate correspondence with other nearby operators. • Monitor well pressure, temperature, and annulus pressure to verify well operation within permitted status and assess the potential for mechanical integrity issues to have occurred from the seismic event. • If evidence of mechanical integrity failure, cease injection, notify the UIC Program Director within 24 hours, and, if the loss of mechanical integrity may endanger the USDW, implement the emergency and remedial response plan approved by the UIC Program Director.
	• Collect fluid samples from above-zone monitoring well and USDW monitoring wells. • Review seismic and operational data to identify potential source areas for a release above the UCCZ. • Within 30 days of the triggering seismic event, determine causality and if deemed causally related propose appropriate corrective measures to our operations. • Report findings to the UIC Program Director and implement corrective measures if warranted. • Operations will resume upon UIC Program Director concurrence that necessary remedial or corrective measures have been taken such that the risk to USDW is in compliance with EPA standards for protection of human health and the environment.
[1] Specified magnitudes determined by local or U.S. Geological Survey seismic monitoring stations or reported by the U.S. Geological Survey National Earthquake Information Center using the national seismic network. [2] Based on Texas Railroad Commission Seismicity Review (RRC, 2024)	

Response Personnel and Equipment

Site personnel, Project personnel, and local authorities will be relied upon to implement this ERRP and will be dispatched in the case of an emergency. In the event of an emergency, appropriate city, county, and state emergency responders and agencies may be notified based on severity of the risk. Contact information for ExxonMobil Emergency Authorities and state and local emergency services are outlined in Table 8-4 and Table 8-5, respectively.

A site-specific emergency contact list will be developed and maintained during the life of the Project. ExxonMobil will provide the current site-specific emergency contact list to the UIC Program Director.

Table 8-4: Contact Information of ExxonMobil Emergency Authorities

Name	Title	Telephone Number
CBI [redacted]	Vice President	CBI [redacted]
CBI [redacted]	Emergency Preparedness & Response Advisor	CBI [redacted]
CBI [redacted]	Public & Government Affairs Advisor	CBI [redacted]

Table 8-5: Emergency Services

Agency	Telephone Number
Beaumont Fire and Rescue Station 1	911 or (409) 880-3901
Jefferson County Sheriff	911 or (409) 835-8411
Jefferson County Public Health Unit #1	(409) 835-8530
Jefferson County Office of Emergency Management	(409) 835-8757
Texas Division of Emergency Management	(512) 424-2208
Texas Department of Public Safety	(512) 424-2000
State of Texas Spill-Reporting Hotline	1-800-832-8224
Texas Parks and Wildlife Department	(512) 389-4800
EPA Region 6	800-887-6063
EPA Class VI Contact – Brandon Maples	214-665-7252
Texas Department of Natural Resources	(512) 389-4800
Jefferson County Local Emergency Planning Committee	(409) 835-8757
National Response Center	1-800-424-8802
State of Texas Spill-Reporting Hotline	1-800-832-8224
EPA National Response Center (24 hours)	(800) 424-8802

Necessary equipment for emergency and remedial response may vary depending on the event. Generally, no specialized equipment will be required for response actions (such as cessation of injection, well shut-in, and evacuation). If specialized equipment (such as a drilling rig or logging equipment) is required, ExxonMobil will be responsible for its procurement.

Communications Plan and Emergency Notification Procedures

As appropriate, ExxonMobil will communicate to the relevant public authorities about an event that may require emergency response so that the public understands the emergency event and if there are any environmental, health, or safety concerns. Based on the emergency event, ExxonMobil will determine the appropriate information, timing, and communication method for the event. This information may include potential impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

If required, ExxonMobil will also communicate with other entities who may need to be informed about or act in response to the event. These may include local water purveyors or operators, CO2 suppliers, pipeline operators, oil and gas operators, landowners, and other departments or authorities as guided by the UIC Program Director.

Flood Hazard Risk

Injection Wells No. 01, No. 02, and No. 03 and the surrounding area are designated as Federal Emergency Management Agency flood hazard zone X (unshaded). Flood hazard zone "X" (unshaded) corresponds to areas determined to be outside of the 500-year floodplain. This zone is an area of minimal flood hazard, which is higher than the elevation of the 0.2-percent-annual- chance flood. The well locations and Federal Emergency Management Agency flood zones are shown in Appendix G.

Plan Review

The UIC Program Director will evaluate this proposed ERRP to verify that ERRP meets the requirements of 40 CFR 146.94(a) and that the plan accounts for all site-specific conditions. The approved ERRP is enforceable, whether or not it is a condition of the permit, because the plan itself and UIC Program Director's approval are required by the Class VI Rule [40 CFR 146.93(a)].

This ERRP shall be reviewed:

- At least once every five years following its approval by the permitting agency [40 CFR 146.94(d)].
- Within one year of any AoR reevaluation [40 CFR 146.94(d)(1)].
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director [40 CFR 146.94(d)(2)]; or
- When required by the Director [40 CFR 146.94(d)(3)].

If the review indicates that no amendments to the ERRP are necessary, ExxonMobil will provide the permitting agency with the documentation supporting the “no amendment necessary” determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within 30 days following an event that initiates the ERRP review procedure.

The amended plan must be approved by the UIC Program Director and would then be incorporated into the Class VI Permit. If significant changes to the plan are needed, the UIC Program Director may need to modify the permit. A permit modification under 40 CFR 144.39 would require notification of the public and an opportunity for comment. Minor changes to the plan, as defined under 40 CFR 144.41, do not require a permit modification or a public process under 40 CFR Part 124.

Staff Training and Exercise Procedures

Personnel will be trained in their duties and responsibilities related to these facilities. Emergency Response Drills will be conducted annually via simulated onsite or table-top scenarios. All plant personnel, visitors, and contractors must complete a plant overview orientation before entering the facilities. ExxonMobil will coordinate with local mutual aid emergency responders over the potential hazards and response scenarios of the site.

Trainings that have and will be provided include topics such as characteristics of carbon dioxide, oxygen displacement, leak detection and identification, emergency response, and isolation and incident management. Specific trainings to be provided could include:

- Incident Command System for Initial Response ICS-100/200
- 24-hour Hazardous Waste Operations and Emergency Response (HAZWOPER) training
- CO2 training course