RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO GEOLOGIC STORAGE AND ASSOCIATED INJECTION OF ANTHROPOGENIC CARBON DIOXIDE (CO2)

Milestone Carbon Midland CCS Hub, LLC (P-5 # 101847)
840 Gessner Road, Suite 600
Houston, TX 77024

Class VI Permit Number: 57099
Project/Facility Name: South Midland Facility
County: Upton, District 7C

Effective Date: xxxxxxx, 2026
Expiration Date: Life of the project, if injection begins within five (5) years from the effective date; otherwise, a renewal application must be filed with a fee within 21 days before xxxxxxx, 2031

Authority is granted to inject **anthropogenic CO2** into the well identified herein in accordance with pursuant to the Texas Water Code, Chapter 27, the Texas Natural Resources Chapter 91, and Underground Injection Control (UIC) regulations of the Railroad Commission of Texas, codified at Title 16, Part 1, Chapter 5 of the Texas Administrative Code (16 TAC) Subchapters A and B, §§5.101, 5.102, 5.201, 5.202, 5.203, 5.204, 5.205, 5.206, 5.207, and 5.208, and based on information contained in the final application dated 01/27/26, subject to the following terms and conditions:

TABLE 1: GENERAL INFORMATION

Source of CO2	Total CO2 Storage Mass (Million Metric Tons)	Duration of Injection (Years)	Top Confining Zone Formation Name	Injection Zone Formation Name
Nearby Oil and Gas Processing Sources, Direct Air Capture Facilities, Power Plants and/or Cement Plants	11.9	12	Woodford Shale	Ellenburger and Siluro-Devonian

TABLE 2: INJECTION WELL IDENTIFICATION AND PERMIT PARAMETERS

Well Name & No.	Well Location Lat/Long (NAD 83)	UIC No.	Top Inj. Interval, TVD (Feet)	Bottom Inj. Interval, TVD (Feet)	Max. Injection Mass Rate (Metric tonnes per day)	Max. Surface Injection Pressure (psi)	Max. Bottom Hole Injection Pressure (psi)
Midland CCS #2	31.615788/ -101.990004	TBA	12,200	13,849	3,086	4,000	7,875

TABLE 3: MONITOR WELLS IDENTIFICATION

Well Name & No.	Latitude (NAD 83)	Longitude (NAD 83)	Purpose	Total Depth, TVD (Feet)	Anticipated Drill Date
Midland IZM #2	31.608086	-101.983038	In-Zone Monitoring Well	13,785	2026
Midland USDW #2	31.615586	-101.990004	USDW Monitoring Well	1,300	2026
Midland NSSW #1	31.602452	-101.975692	Near Surface Seismicity and Water Well	300	2026
Midland NSSW #2	31.596219	-102.005364	Near Surface Seismicity and Water Well	300	2026
Midland NSSW #3	31.649299	-102.023221	Near Surface Seismicity and Water Well	300	2026
Midland NSSW #4	31.655552	-101.937328	Near Surface Seismicity and Water Well	300	2026
Midland NSSW #5	31.710443	-102.012969	Near Surface Seismicity and Water Well	300	2026

STANDARD CONDITIONS:

1. The operator must submit a proposed schedule at least **30 days** to District Office and notify at least **48 hours** prior to:

   a. beginning any well completion, workover or remedial operation
   b. conducting any required test, logging or surveys

   All information and test results must be filed with SIP unit using the email SIP@rrc.texas.gov. and a copy to the District Office, which shall be signed and certified.

2. Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.

3. After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.

4. Before long string casing is installed, the operator must run logs appropriate to geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.

5. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

6. The well must be constructed using CO2 compatible materials.

7. The wellhead must be equipped with a pressure observation valve on the tubing and for annulus.

8. The well must use alarms and automatic shut-off systems designed to alert and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges.

9. The annulus between the tubing and the long string casing must be filled with a corrosion inhibiting fluid and must maintain on the annulus a pressure, that exceeds the operating injection pressure.

10. The total volume of CO_2 injected into the storage facility must be metered through a master meter. The volume and/or mass of CO_2 injected into each injection well must be metered through an individual well meter. If mass is determined using volume, the operator must provide calculations.

11. Prior to injection, whole cores or sidewall cores of the injection and confining zones; and formation fluid samples from the injection zone must be taken. Thereafter, a detailed report prepared by a log analyst that includes well log analyses, core analyses and formation fluid sample information such as temperature, pH, conductivity must be submitted.

12. Must provide the chemical composition and temperature of the CO_2 stream.

13. An annulus pressure test must be performed prior to injection and at least once **every five years** thereafter, or subsequently after any work over. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test results must be submitted in accordance with the instructions of **Form H-5** within **30 days** after the testing.

14. Prior to injection, the operator must perform an **initial** pressure fall-off or other test and submit a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO_2.

15. The injection pressure, rate, temperature, volume and/or mass, and the pressure on the annulus and annulus fluid volume added must be monitored **daily** and reported **semi-annually** on a monthly basis on Form H-10.

16. At least **once per year** until the injection well is plugged, the external mechanical integrity of the casing must be performed using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs). The results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log must be submitted.

17. Within **30 days** after completion, a new Form W-2 and Log must be filed to show the current completion status of the well. The date of the injection well permit, and the permit number must be included on the new Form W-2.

18. Every **five years** or more frequently the AoR will be reevaluated, and the resultant information must be submitted in an electronic format.

19. The operator must submit an **annual report** detailing the re-calculated AoR unless the operator submits a statement signed by an appropriate company official confirming that monitoring and operational data supports the current delineation of the AoR on file with the Commission.

20. Injection fee. The operator must pay the Commission **an annual fee** of $0.025 per metric ton of CO_2 injected into the geologic storage facility.

21. Post-injection care fee. The operator must pay the Commission **an annual fee** of $50,000 for each year that the operator does not inject into the geologic storage facility until the director has authorized storage facility closure.

22. The operator may transfer the facility permit to another operator and must submit written notice of an intended permit transfer to the director at least **45 days** prior to the date the transfer of operations is proposed to take place.

23. The operator must identify each location in which geologic storage activities take place, including each injection well, with a sign that meets the requirements specified in §3.3(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign must include a telephone number where the operator or a representative of the operator can be reached **24 hours a day**, **seven days a week** in the event of an emergency.

24. The operator of a geologic storage facility must comply with the requirements of Chapter 5, subchapter B as well as with all other applicable Commission rules and orders, including the requirements of Chapter 8 of this title (relating to Pipeline Safety Regulations) for pipelines and associated facilities.

25. Within **30 days** of receipt of this permit, the permittee shall certify to the Director in an electronic format, that the operator has read and is familiar with all terms and conditions of this permit. This certification shall be signed and made in accordance with requirements of Title 16 TAC §5.207(c) and (d).

26. The permittee may not commence injection until the Director has given a **written authorization** to commence injection.

SPECIAL CONDITIONS:

1. The well will be completed as an open-hole with following conditions:
    a. Run a radial Cement Bond Log (CBL) in the Midland CCS No. 2 injection well to demonstrate and document that no channeling or other cement deficiencies exist in the cement sheath surrounding the 7-5/8-inch casing.
    b. Conduct a Formation Integrity Test (FIT) in the Midland CCS No. 2 injection well immediately below the casing shoe after cementing the 7-5/8-inch production casing to confirm that there is no possibility of fluid migration above this casing shoe (demonstrating and documenting that complete zonal isolation of the injection reservoirs below has been attained).
    c. Report the results of the CBL logging and FIT at the 7-5/8-inch casing shoe to the SIP unit using the email SIP@rrc.texas.gov. and a copy to the District Office and must obtain approval prior to drilling the final 6-1/8-inch hole section through the injection reservoir interval down to the final total depth (TD) of the well.
    d. The well must be configured such that an additional long-string casing or a liner can be set and cemented through the whole injection interval if future conditions indicate such control is necessary.
2. Injection cannot begin until a **surety bond** in an amount of **$20,957,610** has been filed. The bond must be renewed and continued in effect until the conditions of the bond or letter of credit have been met or its release is authorized. An **annual** update of the cost estimate to increase or decrease to account for any changes must be provided within **60 days** prior to the anniversary date of the establishment of the financial instruments used to comply. Whenever the current cost estimate increases or decreases, the face amount of the financial assurance instrument may be increased or reduced to the amount of the current cost estimate.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the injection operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON **xxxxxx, 2026**

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Rob Castillo, Manager
Special Injection Permits Unit

Class VI Permit Condition & Details

Table of Contents

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall 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 (USDW) or any unauthorized geologic zones. The objective of this permit is to prevent the movement of fluids into or between USDW or into any unauthorized geologic zones consistent with the requirements of **16 TAC §§5.203(d)(1)(C)**, **5.203(e)(1)(A)(i)** and **5.203(j)(2)(H)**. Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Texas Water Code, Chapter 27, and the Texas Natural Resources Code, Chapter 91. 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 shall be construed to relieve the permittee of any duties under applicable regulations.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the RRC Class VI UIC Program, hereinafter, 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 **16 TAC §5.202(d)(2)(A)**. The filing of a request for a permit modification, revocation and reissuance, or termination, or notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition in accordance with **16 TAC §5.206(o)(2)(K)**.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify a permit to make the corrections or allowances for minor changes in the permitted activity as listed in **16 TAC §5.202(d)(2)(A)(viii).** Any permit modification not processed as a minor modification under **16 TAC §5.202(d)(2)(A)(viii)** shall be made for cause, and with a draft permit and public notice as required in **16 TAC §5.204**.

3. **Transfer of Permit –** An operator may transfer its geologic storage facility permit to another operator if the requirements of **16 TAC §5.202(c)** are met. A new operator shall not assume operation of the geologic storage facility without a valid permit in accordance with **16 TAC §5.202(c)** and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable under **16 TAC §5.208(b)**, 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 the Texas Public Information Act, Texas Government Code, Chapter 552, any information submitted to the RRC pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim shall be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, the RRC may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in the Texas Public Information Act, Texas Government Code, Chapter 552. Claims of confidentiality for the following information will be denied:

1. The name and address of the permittee; and
2. Information which 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 Texas Water Code, Chapter 27, or the Texas Natural Resources Code, Chapter 91, and the RRC's UIC regulations specified at **16 TAC §5.102**. Unless specifically 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 shall not construct, operate, maintain, convert, plug, abandon, or conduct any other 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 the movement of any contaminant into the USDW, the Director may take enforcement action or prescribe such additional requirements for construction, corrective action (including closure of the injection well), operation, monitoring, or reporting as are necessary to remediate and prevent such movement.

2. **Duty to Comply –** The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of **16 TAC §5.206(o)(2)(A)** and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

3. **Duty to Reapply –** If the permittee wishes to continue an activity regulated by this permit after its expiration, the permittee shall apply for and obtain a new permit.

4. **Penalties for Violations of Permit Conditions –** Any person who violates a permit requirement is subject to civil and/or criminal penalties and other enforcement action

under the Texas Natural Resources Code, Title 3, Section 91.143 and Texas Water Code, Chapter 27. Any person who willfully violates permit conditions may be subject to criminal prosecution under the Texas Natural Resources Code, Title 3, Section 91.143 and Texas Water Code, Chapter 27.

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 in accordance with **16 TAC §5.206(o)(2)(B)**.

6. **Duty to Mitigate –** The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit in accordance with **16 TAC §5.206(o)(2)(C)**.

7. **Proper Operation and Maintenance –** The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance include, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit by **16 TAC §5.206(o)(2)(D)**.

8. **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 which 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 to the Director, upon request, within a time specified, electronic copies of records required to be kept by this permit by **16 TAC §5.206(o)(2)(H)**.

9. **Inspection and Entry –** The operator shall allow any member or employee of the Commission, on proper identification, to by **16 TAC §5.206(o)(2)(I):**

    (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

    (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are 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 Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

10. **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 **16 TAC §§5.206(o)(2)(L), 5.207(c)** and **5.207(d)**.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the area surrounding the injection well where USDWs may be endangered by the injection activity. The area of review was delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved AoR and Corrective Action Plan (CAP) included as Attachment A, which is an enforceable condition of this permit, and shall meet the requirements of **16 TAC §5.206(g)**.

2. As documented in Attachment A, there are no wellbore penetrations within the AoR that require plugging because no pre-existing wellbores penetrate the injection zone or confining layer.

3. Every five (5) years as specified in the AoR and CAP, or more frequently when monitoring and operational conditions warrant, the permittee shall reevaluate the AoR and perform corrective action in the manner specified in **16 TAC §5.206(g)** and update the AoR and CAP or demonstrate to the Director that no update is needed. Reevaluation of the AoR and CAP shall meet the requirements of **16 TAC §5.203(d)(1)(A) - (C)** and shall include a new survey of wells within the existing or modified AoR.

4. Following each AoR reevaluation or a demonstration that no evaluation is needed, the permittee shall submit a report of the resultant information in an electronic format to the Director for review and approval. Once approved by the Director, the revised AoR and CAP will become an enforceable condition of this permit.

H. FINANCIAL RESPONSIBILITY

The permittee shall maintain financial responsibility and resources to meet the requirements of **16 TAC §5.205** for the life of this permit and through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized by the Director as described in Section P of this permit. The permittee shall use financial instruments as listed in **16 TAC §5.205(c)(2)(D)** to cover all costs associated with the requirements of this permit. The approved financial responsibility and estimated costs for this permit are found in Attachment J and in the administrative record of this permit.

1. **Costs to be Covered –** The financial instrument(s) shall be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of **16 TAC §5.203(d)(2)**.

   (b) Injection well plugging (that meets the requirements of **16 TAC §5.203(k).**

   (c) Emergency and remedial response (that meets the requirements of **16 TAC §5.203(l).**

   (d) Post injection site care and site closure (that meets the requirements of **16 TAC §5.206(m)**.

2. **Cost Estimate Updates and Adjustments –** A detailed written estimate for each phase is included in Attachment J of this permit. The cost estimates must be performed for each phase separately and must be based on the costs to the Commission of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator. and the dollar amount of the financial assurance shall be approved by the Director in accordance with **16 TAC §5.205(c)(2)(C)(i).**

   (a) A qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The owner or operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act in accordance with **16 TAC §5.205(c)(2)(C)(ii).**

   (b) During the life of this permit, the permittee shall adjust the cost estimate for annual inflation and any amendments made to the Project Plans included as Attachments A-J of this permit, which address costs associated with items (a) through (d) in Section H(1) of this permit. The permittee shall adjust cost estimates annually at least 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format in accordance with **16 TAC §5.205(c)(2)(E).** All cost and Project Plan adjustments are subject to the Director's approval.

3. **Notification –**

   (a) Whenever a cost estimate increases to an amount greater than the face amount of a controlling financial instrument, the permittee, at least 60 days after the increase, shall 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 financial responsibility instruments to cover the increase. 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 in accordance with **16 TAC §5.205(c)(2)(G)**.

(b) The permittee shall notify the Director by certified mail and in an electronic format of adverse financial conditions that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action and/or Emergency and Remedial Response. The notice of bankruptcy shall be filed in accordance with **16 TAC §§3.1(f)** (relating to Organization Report; Retention of Records; Notice Requirements) and **5.205(d)(1)**. Such notice shall be provided to the RRC's Office of General Counsel and to the Director.

(i) The owner or operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the owner or operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business in accordance with **16 TAC §5.205(d)(2)**.

(ii) Upon the incapacity of a bank or surety company by reason of bankruptcy, insolvency or suspension, or revocation of its charter or license, the Commission must deem the owner or operator to be without bond coverage in accordance with **16 TAC §5.205(d)(3).** The Commission must issue a notice to any owner or operator who is without bond coverage and must specify a reasonable period to replace bond coverage, not to exceed 60 days.

I. WELL CONSTRUCTION

The design and specifications for the injection well, injection zone monitoring wells, confining zone monitoring wells, and the USDW monitoring wells are included in Attachment B of this permit.

1. Injection Well Construction – The well shall be constructed in accordance with **16 TAC §§3.13** and **5.203(e)(1)** with an exception given by the Director to **16 TAC §5.203(e)(B)(v)** allowing an <u>open-hole well completion</u> (no casing, liner, or cement) through the injection zone. Well construction permitted with this exception meets all federal Class VI UIC well construction requirements as stipulated in **40 CFR §146(b).** This well construction exception will allow optimal connectivity with, and injectivity into, the fractured injection reservoir and will cause no increase in risk to USDWs. The design and construction shall allow continuous monitoring of the annulus between the long string casing and the injection tubing and accommodate testing devices and workover tools with the following conditions:

a. Run a radial Cement Bond Log (CBL) in the Midland CCS No. 2 injection well to demonstrate and document that no channeling or other cement deficiencies exist in the cement sheath surrounding the 7-5/8-inch casing.

b. Conduct a Formation Integrity Test (FIT) in the Midland CCS No. 2 injection well immediately below the casing shoe after cementing the 7-5/8-inch production casing to confirm that there is no possibility of fluid migration above this casing shoe (demonstrating and documenting that complete zonal isolation of the injection reservoirs below has been attained).

c. Report the results of the CBL logging and FIT at the 7-5/8-inch casing shoe to the SIP unit using the email SIP@rrc.texas.gov. and a copy to the District Office and must obtain approval prior to drilling the final 6-1/8-inch hole section through the injection reservoir interval down to the final total depth (TD) of the well.

d. The well must be configured such that an additional long-string casing or a liner can be set and cemented through the whole injection interval if future conditions indicate such control is necessary.

During construction, the permittee may make changes to the design of the injection well consistent with the conditions of this permit. If changes are made to the design of the well, notification shall be made to the Director, and the construction changes shall be provided for review and approval by the Director before installation. Once the construction of the well is completed, and prior to authorization to inject, the permittee shall submit the final, as-built construction specifications and diagrams within 30 days for review and approval by the Director. Any deviations from the proposed design and as-built construction of the well shall be noted. If the changes in well design are significant, the Director may require this permit to be modified.

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 **16 TAC §5.206(b)(6)**.

3. **Casing and Cementing –** The wells shall be cased and cemented in accordance with **16 TAC §§3.13 and 5.203(e)(1)(B)**. Casing, cement, or other materials used in the construction of the well shall have sufficient structural strength for the life of the geologic sequestration project. All well materials shall be compatible with all fluids with which the materials may be expected to come into contact and shall meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program shall prevent the movement of fluids into or between USDWs for the expected life of the well. The casing and cement used in the construction of this well are shown in Attachment B of this permit and in the administrative record for this permit. Any changes shall be submitted in an electronic format for approval by the Director before installation.

4. **Tubing and Packer Specifications –** The tubing and packer design shall meet the requirements of **16 TAC §§3.13** and **5.203(e)**. Tubing and packer materials used in the construction of the well shall be compatible with fluids with which the materials may be expected to come into contact and shall meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. Injection shall 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 in accordance with **16 TAC §5.203(e)(1)(C)(i)**. The tubing and packer used in the well are represented in engineering drawings contained in Attachment B of this permit. Any change shall be submitted in an electronic format for review and approval by the Director before installation.

5. **Sampling and Monitoring Devices –** The permittee shall install and maintain in good condition all devices required to measure, monitor, and record the data required by Attachment F of this permit. The permittee shall ensure that the devices installed and methods used are sufficient to represent the activity being measured, monitored, or recorded. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a back-up system if the primary continuous monitoring devices become inoperable. The Director shall be notified of such occurrences, and continuous monitoring devices should be repaired or replaced as soon as practicable. If this period of time is extensive in the opinion of the Director, injection activities shall cease until such time that normal monitoring is restored. The permittee shall ensure the wells' construction and near-wellhead design is appropriate for the collecting of samples and fulfilling of all monitoring requirements of this permit. The permittee shall ensure all gauges used for monitoring and testing are properly calibrated.

6. **Construction of Monitoring Well – 16 TAC §§5.203(j)(2)(D)(i), 5.203(j)(2)(D)(ii), 5.203(j)(2)(E),** and **5.203(j)(2)(G)** require monitoring of the carbon dioxide plume and pressure front of the confining and injection zones and monitoring of USDW located above the injection zone. These sections are incorporated by reference into this permit. USDW, confining zone, and injection zone monitoring wells shall be constructed in the manner depicted in Attachment B of this permit using materials that are compatible with the injected fluids. All monitoring wells shall be constructed in a manner to provide 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 shall be included in the Pre-injection Testing Report to be submitted to the Director per Section J of this permit.

J. PRE-INJECTION TESTING

Testing is required during the construction of the well in accordance with **16 TAC §5.203(f)**. This testing is required to verify the geology of the well site to ensure compliance with the well construction requirements in accordance with **16 TAC §5.203(e)** and to test viability of the wells to meet the stipulated operational requirements. The pre-injection testing plan is included as Attachment D of this permit.

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at **16 TAC §5.203(f)**. This testing shall 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 shall include:

      (i) Deviation checks that meet the requirements of **16 TAC §5.203(f)(1)(A).**

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of **16 TAC §5.203(f)(1)(B).**

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of **16 TAC §5.203(f)(1)(D).**

(iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of **16 TAC §5.203(h)** and

(v) Any alternative methods (MIT), provided that the type of test has the written approval of the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).**

(b) Documentation of the measured fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of **16 TAC §5.203(f)(3)(A)**.

(c) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of **16 TAC §5.203(f)(3)(B)**.

(d) Tests to determine well-specific data regarding the injection and confining zones. These tests shall determine fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of **16 TAC §§5.203(f)(2)(C)** and **5.203(f)(3)(B)**.

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of **16 TAC §5.203(f)(2),** including:

(i) A pressure fall-off test or

(ii) Other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for pre-operational testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee shall provide the Director with the opportunity to witness all logging, sampling, and testing required under this permit and submit notice at least 48 hours in advance of any actual activity in accordance with **16 TAC §5.206(i)**.

K. INJECTION WELL OPERATING REQUIREMENTS

1. Outermost Casing Injection Prohibition – Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. Injection Fluids/Carbon Dioxide Sources – The permittee will sequester CO_2 source(s) from multiple, nearby facilities including natural gas processing plants, direct air capture facilities, power plants, and/or cement plants within a radius of 50 miles of the injection facility. The Permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by the Director.

3. **Injection Pressure Limitation –** Except during stimulation, the permittee shall ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). Under no circumstance 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 maximum injection pressure limit is listed in Attachment E of this permit.

4. **Stimulation Program –** All stimulation activities shall be approved by the Director prior to conducting the stimulation. The permittee shall carry out the Stimulation Program in accordance with Attachment C of this permit.

5. **Additional Injection Limitations –** No injection fluid other than that identified on Page 1 of this permit may be injected except fluids used for stimulation, rework, and well tests as approved by the Director. Injection shall occur within the injection tubing.

6. **Annulus Fluid –** The permittee shall fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

7. **Annulus/Tubing Pressure Differential –** Except during workovers or times of annulus maintenance, the permittee shall maintain pressure on the annulus that exceeds the operating injection pressure as specified in Attachment E of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDW.

8. **Automatic Alarms and Automatic Shut-off System –**

   (a) The permittee shall:

      i. 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

      ii. 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 after the last approved demonstration.

      iii. Establish well-specific thresholds for activating the shut-off system and submit revised Attachments E & H.

   (b) Testing under this Section shall involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or the Director’s representative unless the Director authorizes an unwitnessed test in advance. The permittee shall provide notice in an electronic format at least 30 days prior to running the test and shall provide the Director or the Director’s representative with the opportunity to witness the test. The test shall be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing shall be submitted to the Director in an electronic format within the time period specified in Section O(4) of this permit.

9. **Precautions to Prevent Well Blowouts –** Except at specific times as approved by the Director, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The wellbore shall 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 which can resist the pressure differential. A blowout preventer shall be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall follow procedures such as those below to ensure that a backflow or blowout does not occur:

   (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 Shall Cease –** Injection shall cease when any of the following circumstances arises:

    (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) A significant unexpected change in the annulus or injection pressure;

    (e) The Director determines that the well lacks mechanical integrity;

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

    (g) Conditions described in Section M(C)(3), Seismic Event Response, occur;

    (h) The Director determines the site is no longer suitable for injection based on new information;

    (i) The Director determines that the permittee is unable to maintain compliance with any condition of this permit or regulatory requirement, and the Director determines that injection should cease.

11. **Approaches for Ceasing Injection –**

    (a) In all instances where injection ceases, the permittee shall immediately cease injection and shut-in the well as outlined in the Emergency and

Remedial Response Plan (Attachment H of this permit), and the Permittee must get approval from the Director to resume injection.

(b) 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 of this Permit.

L. MECHANICAL INTEGRITY

The injection wells shall maintain internal (casing, tubing and packer) and external (fluid movement into geologic units other than the injection zone) mechanical integrity for the entirety of its operational life. No significant leaks in the casing, tubing, or packer can occur without corrective actions. The determination of whether the injection well has mechanical integrity is at the discretion of the Director. Mechanical integrity is determined through testing and test procedures approved by the Director. Approved mechanical integrity testing procedures are in the Testing and Monitoring Plan in Attachment F of this permit. Other tests and/or procedures not listed in this plan will be considered by the Director for approval.

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 shall have and maintain mechanical integrity consistent with **16 TAC §5.203(h).** To meet these requirements, mechanical integrity tests/demonstrations shall be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. In order to conduct testing without a RRC representative, the following procedures shall be followed:

(a) The permittee shall submit prior notification in an electronic format at least 30 days prior to testing, including the information that no RRC representative is available, and receive permission from the Director to proceed;

(b) The test shall be performed in accordance with the Testing and Monitoring Plan (Attachment F of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing shall be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing –** The permittee shall conduct a casing inspection log and mechanical integrity testing (MIT) as follows:

(a) After construction, and prior to receiving authorization to inject from the Director, the permittee shall demonstrate internal mechanical integrity of the well. This demonstration is achieved by the performance of the following testing pursuant to **16 TAC §5.203(h)(2):**

(i) A pressure test with liquid or gas;

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E)**.

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to **16 TAC §5.203(h)(2)**:

(i) Tracer surveys such as an oxygen activation log.

(ii) Temperature or noise logs.

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).**

(c) 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 permittee shall continuously monitor injection pressure, injection rate, injection mass, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in **16 TAC §§5.203(h)(1)(C)** and **5.206(e)(2)**.

(d) At least once per year, the permittee shall perform the testing to demonstrate external mechanical integrity pursuant to **16 TAC §5.203(h)(1)(D)** and as listed in Section L(2)(b) of this permit. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(e) After any well repair or workover that may compromise the internal mechanical integrity of the well, the internal mechanical integrity of the well shall be demonstrated by conducting test(s) approved by the Director. In cases where a well has lost mechanical integrity, written approval by the Director is required before the injection can resume. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in Attachment G and it meets the requirements of **16 TAC §5.203(k).** Written approval by the Director is required before plugging operations may commence. All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

(g) The Director may require the use of other tests to demonstrate mechanical integrity other than those listed above, provided that the type of test has the written approval of the Administrator pursuant to requirements at **16 TAC §5.203(h)(2)(E).** All test data shall be sent to SIP@rrc.texas.gov and a copy to District Director.

3. Prior Notice, MIT Procedures and Reporting –

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

(b) The mechanical integrity tests and procedures are listed in Attachments D and F. Use of non-approved tests and procedures may result in disqualification of the tests.

(c) Reports of mechanical integrity demonstrations which include logs shall include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within 30 days of the testing.

4. Gauge and Meter Calibration – Prior to testing, the permittee shall calibrate all gauges and meters used in monitoring and testing required by this permit. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test per **16 TAC §5.206(e)(5)(B)(i)** and the operator and the director must apply methods and standards generally accepted in the industry in accordance with **16 TAC §5.207(a)(1)**.

5. Loss of Mechanical Integrity –

(a) If the permittee or the Director finds that a 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 **16 TAC §5.102(36)** is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee shall:

(i) Cease injection in accordance with Section K(9), and Attachments E or H of this permit;

(ii) Take all steps that are 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 shall be implemented (Attachment H of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) Notify the Director in an electronic format when injection can be expected to resume.

(b) If an automatic shutdown (i.e., downhole or at the surface) is triggered, the permittee shall immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon investigation, the well appears to be lacking mechanical integrity, or if the required monitoring indicates that the well may be lacking mechanical integrity, the permittee shall take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well shall either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to resume injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity for Monitoring Wells –** All monitoring wells shall maintain internal and external mechanical integrity for the entirety of their operational life. No significant leaks in the casing can occur and require corrective actions. The determination of whether the monitoring well has mechanical integrity is at the discretion of the Director. Mechanical integrity tests and procedure for the confining zone, injection zone and USDW monitoring wells are outlined in Attachment F of this permit. Testing and demonstration of monitoring wells shall be conducted on the same schedule as the injection well. Other tests and/or procedures not listed in this plan will be considered by the Director for approval.

7. **Mechanical Integrity Testing on Request from Director –** The permittee shall demonstrate mechanical integrity at any time upon written notification from the Director.

M. SEISMIC EVENT RESPONSE

1. Seismic Monitoring –

(a) Prior to commencing injection, the permittee must deploy and maintain a seismic monitoring system (minimum of one in-ground seismic monitoring station) meeting the equipment specifications to become part the state (TexNet) seismic monitoring network to allow long-term monitoring by TexNet seismologists, and allowing them to determine the presence or absence, magnitude, and hypocenter location, of any induced seismic activity of magnitude 1.8 M or above..

(b) The system should be designed with a surface monitor and/or downhole monitor(s) as required to meet minimum magnitude of completeness (Mc) of 1.8 M or an alternative site-appropriate minimum magnitude approved by the Director in consultation with the State Seismologist, and to appropriately calibrate event magnitudes and hypo central locations. The system shall be calibrated with check-shots, sonic logs, or other local velocity information, preferably in depth.

(c) The permittee shall analyze seismic and other relevant data to determine whether the risk of triggering an earthquake of magnitude 3.5 M or greater is significantly increased by injection. If, after analysis of seismic and other relevant data, the permittee determines that there is such an increase in risk, the permittee shall notify the Director immediately and submit to the Director a mitigation plan for the Director's review within 15 days of that determination. The permittee shall implement the plan as approved by the Director. The appropriate response to seismic events depends on the Magnitude (M) of the seismic event according to the following protocol:

2. **Seismic events not recorded or M less than 2.0 –** Continue normal operations.

3. **Seismic events with M equal to or greater than 2.0 but less than 3.5 –** The permittee shall notify the Director (District Director or Technical Permitting Director) and State Seismologist of any such event within 24 hours, providing information on the status of the injection site. If the annulus pressure of the well decreases below the set alarm, injection operations shall cease. In that situation, within 30 days the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. If the well fails the mechanical integrity test or the permittee identifies any problems with the injection system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than five (5) days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the circumstances and if the situation has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the circumstances. Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, the permittee shall submit the results and any other required documentation to the Director in an electronic format. If after the testing the well demonstrates mechanical integrity and issues that might impact USDWs are not identified, the permittee shall provide a report of those findings to the Director for review and approval. Injection operations cannot resume until the Director grants approval to recommence injection.

4. **Seismic Events with M equal to or greater than 3.5 –** For seismic events equal to or greater than 3.5 M, injection operations shall immediately cease. The permittee shall notify the Director of any such event within 24 hours, providing information on the status of the injection well system. If the annulus pressure decreased below the well's set alarm before shutting in the well, then the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. The permittee shall also perform an evaluation of the external mechanical integrity of the well in accordance with Section L(2)(b) of this permit. If the well fails either the internal or external mechanical integrity test or the permittee identifies any problems with the system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than 30 days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the failure and if the failure has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent recurrence of the failure. Upon completion of the steps to ensure mechanical integrity and

the subsequent mechanical integrity demonstration, the permittee shall submit the results and any other required documentation to the Director. Injection operations cannot resume until the Director grants approval to recommence injection.

N. TESTING AND MONITORING REQUIREMENTS

1. **Testing and Monitoring Plan –** The specific measurement and reporting frequencies are listed in Attachment F.

   (a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan included as Attachment F of this permit and with the requirements at **16 TAC §§5.206(e)**, and **5.206(o)(2)(I)**, and any modifications required by the Director after the effective date of this permit. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit shall 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 Attachment F of this permit. When the test report is submitted, a full explanation shall be provided as to why any approved procedures were not followed. If the approved procedures were not followed, the Director may take appropriate action, including but not limited to, requiring the permittee to re-run the test.

   (b) The permittee shall update the Testing and Monitoring Plan as required by **16 TAC §5.207(a)(2)(D)** to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(1) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall 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.

   (c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis –** The permittee shall analyze the carbon dioxide stream prior to injection and with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of **16 TAC §5.203(j)(2)(A)**.

3. **Continuous Monitoring –** The permittee shall install and use continuous recording devices to monitor the injection pressure (at 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 surface and at injection interval). This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the

requirements of **16 TAC §5.203(j)(2)**. The permittee shall maintain for inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Groundwater (USDW) Monitoring Above the Confining Zone –** The permittee shall monitor groundwater (USDW) 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 shall 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 **16 TAC §5.203(j)(2)(D)**.

5. **Carbon Dioxide Plume and Pressure Front Tracking –** The permittee shall track the extent of the carbon dioxide plume and pressure front using direct and indirect monitoring methods as described in the approved Testing and Monitoring Plan and in accordance with **16 TAC §5.203(j)(2)(E).** The permittee is required to conduct this monitoring in order to detect and locate the carbon dioxide pressure front and the dissolved carbon dioxide plume and use the data to calibrate the AoR model to determine whether modifications to the AoR is necessary. The data collected will be used to monitor the location of the plume and pressure front, evaluate its movement through time, and compare to the plume and pressure front predictions of the AoR model. Tracking the extent of the CO_2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools.

6. **Corrosion Monitoring –** The permittee shall perform corrosion monitoring of the well construction materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with **16 TAC §5.203(j)(2)(C).** This ensures that the well components meet the minimum standards for material strength and performance set forth in **16 TAC §5.203(e)(1)(B)**.

7. **External Mechanical Integrity Testing –** The permittee shall demonstrate external mechanical integrity annually as described in the approved Testing and Monitoring Plan and shall comply with Section L of this permit in order to meet the requirements of **16 TAC §§5.203(h)(1)(D)** and **5.206(e)(1)**.

8. **Pressure Fall-Off Test –** The permittee shall conduct a pressure fall-off test at least once every five (5) years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of **16 TAC §5.203(j)(2)(G)**.

9. **Additional Monitoring –** If required by the Director as provided in **16 TAC §5.203(j)(2)(H)** the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation.). An update shall be made to the Testing and Monitoring Plan, and the subsequent monitoring shall be performed as described in the update.

O. REPORTING AND RECORDKEEPING

The permittee shall submit reports at frequencies described in the approved Testing and Monitoring Plan, and as required by this permit. Reports shall contain all the data and information required to be monitored, gathered and reported by this permit and meet the requirements of **16 TAC §§5.206(c), 5.206(d), 5.206(e),** and **5.207**.

1. **Electronic Reporting –** All reports, submittals, notifications, correspondence to the Director, and records made and maintained by the permittee under this permit shall be in an electronic format. The permittee shall electronically submit all required reports to an address or location as determined by the Director.

2. **Semi-Annual Reports –** The permittee shall submit reports on a semi-annual basis in accordance with **16 TAC §5.207(a)(2)(C).** The reporting period for semi-annual reports will be from January 1 through June 30 and from July 1 through December 31. Reports shall be submitted within 30 days of the end of each reporting period. Semi-annual reports shall 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 shall include all data collected on an annual basis as described in the approved Testing and Monitoring Plan. Reports shall 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:

   (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)(6) of this permit pursuant to **16 TAC §5.206(d)(2)(F)** and the response taken.

   (e) The monthly volume and mass of the carbon dioxide stream injected over the reporting period and the volume and mass injected cumulatively as of the end of the reporting period.

   (f) Monthly annulus fluid volume added or removed; and

   (g) Results of the continuous monitoring required in Section N(3) 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 volume and mass, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and

(ii) Graph(s) of the continuous monitoring as required in Section N(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and mass and flow rate, annulus fluid level, annulus pressure, and temperature shall 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 Testing and Monitoring Plan and described in Section N of this permit.

3. 24-Hour Reporting –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment and any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment H of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such oral reports should 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 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)(7) of this permit (i.e., downhole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement for surface air/soil gas monitoring or other monitoring technologies, if required by the Director in accordance with **16 TAC §5.203(j)(2)(H)** due to any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment H of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five (5) days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain a description of the noncompliance or 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 (Attachment H 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) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit

5. **Advance Notice Reporting –**

(a) **Well Tests –** The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test and submit notice at least 48 hours in advance of any actual activity.

(b) **Planned Changes –** The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted facility. An analysis of any new injection fluid shall 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 shall 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 which may result in noncompliance with permit requirements.

6. **Additional Reports –**

(a) **Compliance Schedules –** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 45 days following each schedule date.

(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 45 days prior to transfer and the requirements of **16 TAC §5.202(c)** have been met. Pursuant to requirements at **16 TAC §5.202(d)(2)(A)(v)(VIII),** 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 **16 TAC §5.203(n)** and by Section H of this permit shall be updated and provided to the Director by any new owner or operator of the well.

(c) **Other Noncompliance –** The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(a) of this permit.

(d) **Other Information –** When the permittee becomes aware of 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, the permittee shall submit such facts or corrected information in an electronic format within 10 days of discovery in accordance with **16 TAC §5.203(p)**.

7. Records and Record Retention –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and 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 a period of at least 10 years from collection.

(b) The permittee shall 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 **16 TAC §§5.206(l), 5.206(m),** and **5.207(e)** until at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until at least 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any 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 shall 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.

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

The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment G) and the approved Post Injection Site Care and Site Closure Plan (Attachment I) and shall comply with the requirements of **16 TAC §§3.14, 5.203(k), 5.205(b), 5.205(c), 5.205(d), and 5.206(k)(6)(A).** 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 indicates and the permittee deems it necessary, or if the Director requires the approved plans in Attachments G and I of this permit to be modified, revised plan(s) shall 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 shall be approved by the Director and shall be incorporated into the permit and are subject to the permit modification requirements at **16 TAC §5.203(k)(3)(A)**.

2. **Required Activities Prior to Plugging –** The permittee shall flush the wells with an inert buffer fluid, determine the post-injection bottomhole pressure, and perform final internal and external mechanical integrity tests prior to injection well plugging. The internal and external mechanical integrity tests shall be performed as required by Section L of this permit.

3. **Notice of Plugging and Abandonment –** The permittee shall notify the Director in writing in an electronic format pursuant to **16 TAC §5.206(k)(6)(A)** least 60 days before plugging, conversion or abandonment of the well. A shorter notice period may be allowed at the discretion of the Director.

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

   (a) The permittee shall receive written approval from the Director before plugging the well and shall plug and abandon the well as required by **16 TAC §§3.14** and **5.203(k),** as described in the approved Well Plugging Plan (Attachment G of this permit).

   (b) Within 30 days after plugging, the permittee shall submit in an electronic format a plugging report to the Director. The report shall be signed and certified by the permittee in accordance with **16 TAC §5.203(k)(4),** and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for ten (10) years following site closure. The report shall include:

      (i) A statement that the well was plugged in accordance with the approved Well Plugging Plan (Attachment G of this permit); 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 USDWs, the permittee shall replug the well as required by the Director.

5. **Temporary Abandonment –** If the permittee ceases injection for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, **16 TAC §5.203(k)**, or make a demonstration of non-endangerment of this well that is satisfactory to the Director while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well shall be tested to ensure that it maintains mechanical integrity, in compliance with the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements in compliance with all requirements of this permit and all applicable regulations.

6. **Post-Injection Site Care and Site Closure Plan –** The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan in Attachment I of this permit and comply with the requirements of **16 TAC §§5.203(m)**, and **5.206(k).** The Post-Injection Site Care period is the length of time anticipated to demonstrate that the carbon dioxide injection poses no threat to USDWs and is an enforceable condition of this permit.

   (a) Upon cessation of injection, the permittee shall either submit in electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

   (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 in accordance with **16 TAC §5.206(k)(1)(B).** The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at **16 TAC §5.203(m)(7)**.

   (c) The monitoring as outlined in the approved Post-Injection Site Care and Site Closure Plan shall define the position of the carbon dioxide plume and pressure front, provide a comparison of data collected to the predictions made by the AoR model, and demonstrate that USDWs are not being endangered in accordance with **16 TAC §§5.206(e)(3)** and **5.206(k)(3)(A)**.

   (d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section P(6)(b) of this permit, 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 in **16 TAC §5.206(k)(3)**. 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 shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment I of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachments G and I of this permit in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the surface site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report shall include the information specified at **16 TAC §5.206(k)(6)**.

(h) The permittee shall 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 **16 TAC §5.206(l)**.

(i) The permittee shall 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 **16 TAC §§5.203(k), 5.206(j)** and **5.206(k)(6).** The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

Q. EMERGENCY AND REMEDIAL RESPONSE

The Emergency and Remedial Response Plan describes actions the permittee shall take to address movement of the injection or formation fluids that may cause endangerment to a USDW during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment H of this permit), which is an enforceable condition of this permit, and comply with the requirements of **16 TAC §5.203(l)**.

1. If the data collected indicates evidence that the carbon dioxide plume and or pressure front may cause endangerment to a USDW, the permittee shall:

(a) Cease injection in accordance with Sections K(9) and Attachments E or H 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.

2. Annual update is required in accordance with **16 TAC §5.207(a)(2)(E).**

(i) Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has:

(ii) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title;

(iii) determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator; and

(iv) Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.

At least every five years, or more frequently if the monitoring and operational data warrant, the permittee shall review and update the Emergency and Remedial Response Plan or demonstrate to the Director that no update is needed. The permittee shall also incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(4) of this permit or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within thirty (30) days of an AoR reevaluation in accordance with **16 TAC §5.207(a)(3),** following any significant changes to the facility such as 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 shall be submitted for review and approval by the Director in accordance with Section H of this permit.

3. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

R. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program as specified in Section J of this permit and in **16 TAC §5.203(f)** are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the wells has been demonstrated in accordance with **16 TAC §§5.102(36)**, **5.203(h)(1)(B)** and **5.203(h)(1)(D)**, and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment A of this permit in accordance with **16 TAC §5.203(d)(1)(C)**;

4. All requirements at **16 TAC §5.203** have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, 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. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with **16 TAC §5.203(e)(1)** and Section I of this permit;

6. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of the permit;

7. The Director has approved demonstration of the alarm system and shut-off system under Section K(7) of this permit; and

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

S. PAYMENT OF FEES TO THE STATE OF TEXAS

In accordance with **16 TAC §5.205**, the permittee shall pay the following fees:

1. **Application Fee for Amendment –** The applicant must pay to the Commission an application fee of $25,000 for each application to amend a permit for a geologic storage facility in accordance with **16 TAC §5.205(a)(1)(B)**.

2. **Injection Fee –** The operator must pay to the Commission an annual fee of $0.025 per metric ton of CO_2 injected into the geologic storage facility in accordance with **16 TAC §5.205(a)(2)**.

3. **Post-Injection Care Fee –** The operator must pay to the Commission an annual fee of $50,000 each year the operator does not inject into the geologic storage facility until the director has authorized storage facility closure in accordance with **16 TAC §5.205(a)(3)**.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by **16 TAC §§5.203, 5.205, 5.206, and 5.207.** The permittee shall comply with these conditions and adhere to these plans as they are approved by the Director by their incorporation into this permit.

A. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

B. WELL CONSTRUCTION PLAN

C. STIMULATION PLAN

D. PRE-INJECTION/PRE-OPERATIONAL TESTING PLAN

E. INJECTION WELL OPERATING CONDITIONS

F. TESTING AND MONITORING PLAN

G. WELL(S) PLUGGING PLAN

H. EMERGENCY AND REMEDIAL RESPONSE PLAN

I. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

J. FINANCIAL ASSURANCE DEMONSTRATION

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment A: Area of Review (AoR) and Corrective Action Plans (CAP)

[40 CFR §146.82, §146.84]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Prepared by

Numeric Solutions, LLC

1536 Eastman Ave, Suite D

Ventura, California 93003

Updated 23 January 2026

Table of Contents

List of Tables

List of Figures

List of Equations

2.0 AREA OF REVIEW (AoR) AND CORRECTIVE ACTION (CA) PLANS [146.82(a)(13), 146.84 (b) (1)]

2.1 AoR Plume Modeling and Delineation Introduction

The Area of Review (AoR) for the proposed Midland CCS #2 project was delineated using a geologic model developed by Milestone based on publicly available data and proprietary 2D seismic. The model predicts CO_2 plume and pressure migration and supports compliance with Class VI regulatory requirements by demonstrating the presence of a suitable injection interval and confining system. While the model will be refined with future data from a planned stratigraphic test well and 3D seismic, current analysis indicates no wells within the AoR penetrate the confining layer or injection interval, and no corrective action is required

2.2 Computational Modeling Approach

Static geologic modeling and dynamic reservoir simulation were used to estimate key subsurface parameters associated with the injection of supercritical CO_2 into the undifferentiated Devonian Formation, through the base of the Silurian-aged Montoya Group and the Ordovician-aged Ellenburger Group—collectively referred to as the “injection units” (see **Section 1.5** for additional stratigraphic details). Together, these units comprise the “Injection Interval.” The primary confining unit, the Woodford Shale, and a secondary seal, the Barnett Shale, were also incorporated into the model.

Model outputs provide critical insights into the spatial extent of the injection plume, pressure propagation, and operational conditions. These outputs form the basis for delineating the Project’s Area of Review (AoR).

To ensure modeling accuracy and computational efficiency, Milestone used industry-standard software, including SLB’s Petrel™ for 3D geologic modeling and Rock Flow Dynamics’ tNavigator® for reservoir simulation.

SLB’s Petrel™ software is a leading platform for subsurface modeling and reservoir characterization in the oil and gas industry. It offers a unified environment where geoscientists and engineers can collaboratively build, visualize, and interpret geological and geophysical models. Petrel™ integrates workflows across various disciplines, such as seismic interpretation, petrophysics, and reservoir engineering, enabling a seamless approach to interpretation, reservoir characterization, and structural and petrophysical static model development. With advanced features like 3D visualization and automated fault modeling, Petrel provides users with powerful tools to analyze data, assess risks, and optimize reservoir performance. The platform’s versatility and robust data integration capabilities make it a valuable tool for visualizing complex reservoirs and subsurface geometries.

Rock Flow Dynamics (RFD) developed tNavigator software, a comprehensive reservoir simulation platform used in the oil and gas industry. tNavigator® integrates geological modeling, reservoir simulation, and production optimization into a single, user-friendly platform. It allows users to build detailed geological models, run simulations, and predict reservoir behavior under various scenarios. Known for its high-performance parallel computing capabilities, tNavigator® efficiently handles complex models, even for large-scale reservoirs, making it a popular choice for companies that require accurate, fast, and reliable simulations. It supports various types of simulations, such as black oil, compositional, thermal, and fractured reservoirs. The platform's flexibility also extends to well management, surface network modeling, and production forecasting, providing a robust suite of tools for optimizing field development strategies.

2.3 Model Background

A representation of the storage reservoir was constructed using 2D seismic interpretation, available well logs, and interpreted formation tops (see Section 13 – Appendix D). SLB's Petrel™ software was used to build a faulted static geocellular model composed of discrete layers, extending from the top of the Mississippian-aged Barnett Formation and underlying Woodford Shale (upper confining interval) to the Precambrian basement below the Ordovician-aged Ellenburger Group (base injection unit). The model includes the following zones: Barnett, Woodford, Devonian, Silurian, Fusselman, Simpson, and Ellenburger. The model's base is the base of the Ellenburger/top of the basement rock. The Cambrian-aged Bliss Formation is not included in the model, as wellbore and seismic data do not confirm whether it is regionally present or occurs only as isolated sands.

The regional geocellular model ("regional grid") spans 874 square miles (approximately 28 miles [X] by 31 miles [Y]) across northern Upton County and southern Midland County. It consists of approximately 22 million hexahedral grid cells, each 500 by 500 ft in the XY direction (nI = 299, nJ = 326). The model includes 226 layers (K), with layer thickness varying by zone and averaging 10 ft.

A subset of this regional grid was used as input to tNavigator® (the "dynamic grid"), a compositional finite-difference reservoir simulator developed by Rock Flow Dynamics. tNavigator® is well-suited for modeling CO_2 behavior due to its equation-of-state (EOS) algorithms and high-performance computing capabilities. It was used to simulate subsurface behavior of supercritical CO_2, forecast pressure buildup, and generate outputs for evaluating the AoR boundary.

To date, Milestone has not drilled a stratigraphic test well or conducted laboratory testing on core samples to directly measure relative permeability, porosity, capillary pressure, or geomechanical properties of the injection and confining units. Additionally, 3D seismic data have not yet been acquired for the Area of Review (AoR). However, both 3D seismic acquisition and stratigraphic drilling are planned upon reaching key commercial milestones. The current model relies on 2D seismic, existing well logs, and publicly available data and research related to the injection and confining zones. Two 2D seismic lines near the AoR were interpreted to identify faults and refine the structural framework.

Petrophysical log analysis and offset water samples were used to determine formation depth and salinity for key Mississippian through Ordovician units. These logs also informed evaluations of porosity, permeability (see **Table 2-1**), lithology/facies, reservoir quality, and estimated geomechanical properties. Wells with appropriate data were used as control points in the model to distribute these key parameters. The distribution of rock and petrophysical properties (e.g., facies, porosity, and permeability) was modeled using geostatistical estimation from upscaled logs, guided by variograms for each modeled zone.

Table 2-1: Storage Reservoir Petrophysical Wells
Summary of wells used to develop property attributes within the regional static model domain.

API14	Well Name	Zone at TD	Poro. (PHIT)	Perm. (KA)
42-461-31511	AMACKER 1-67	Simpson	✓	✓
42-461-31788	BENEDUM /SPRABERRY/ UNIT 202	Fusselman	✓	✓
42-329-33390	DAVIDSON "27" 1D	Silurian	✓	✓
42-461-40597	DAVIDSON UNIT 1 0106BH	Basement	✓	✓
42-461-33079	GIDDINGS ESTATE FEE 1247	Ellenburger	✓	✓
42-461-34165	HALAMICEK 7901H	Simpson	✓	✓
42-461-31960	MANN28 1	Ellenburger	✓	✓
42-461-30288	MCCUISTION COMMUNITY HOSPITAL 1	Devonian	✓	✓
42-461-33430	MCELROY RANCH 24A	Ellenburger	✓	✓
42-329-34681	MIDKIFF "A" 2608	Devonian	✓	✓
42-461-32196	NEAL, H. F. 1	Simpson	✓	✓
42-461-32673	PECK 1	Ellenburger	✓	✓
42-461-33369	PEGASUS FIELD UNIT #3 1316H	Fusselman	✓	✓
42-461-32586	PEGASUS FIELD UNIT #3 2012	Ellenburger	✓	✓
42-461-32374	PEMBROOK, RALPH 405	Ellenburger	✓	✓
42-461-32788	POWELL 34 1	Ellenburger	✓	✓
42-461-34581	RAILWAY RANCH 9 1H	Devonian	✓	✓
42-461-32329	ROSENBAUM 1	Ellenburger	✓	✓
42-461-32160	TIPPETT SPRABERRY UNIT 208A	Ellenburger	✓	✓
42-461-32444	VAUGHN DEEP 1	Ellenburger	✓	✓
42-461-34568	WINDHAM-CLARK 103 UNIT 1H	Devonian	✓	✓
42-461-30531	XBC GIDDINGS ESTATE 1238D	Ellenburger	✓	✓
Count			**22**	**22**

To model the subsurface behavior of supercritical CO_2, a compositional isothermal simulation was conducted to predict the diffusion of the injectate at pressures below 90% of the fracture gradient. The selected model characterizes CO_2 movement and trapping based on the available data. To evaluate the extent of the AoR, the model was used to assess the incremental change in reservoir pressure and gas saturation[1] within the model domain. The AoR was defined as the area where gas saturation is predicted to exceed two (2) percent from the start of injection through plume stabilization. See **Section 2.9** and **Section 2.10** for additional information on the AoR.

[1] The injectate stream, primarily composed of CO_2 gas at standard temperature and pressure, is modeled in the subsurface under conditions exceeding the critical point. Under modeled reservoir conditions, the CO_2 exists in a supercritical phase. The simulator tracks the inventory of CO_2 mass and other injectate components within the Model domain, categorizing them as “gas” properties. While referred to as "gas" in the simulation output, the physical behavior corresponds to that of a supercritical fluid. Therefore, in this context, references to gas saturation denote the saturation of the entire injection stream, which remains in the supercritical phase throughout the reservoir.

2.4 Static Model Summary

A regional static geocellular model comprising approximately 22 million 500 × 500 ft (XY) hexahedral cells was constructed using SLB's Petrel™ software (**Table 2-2**). Layers were proportionally distributed within each zone, with an average thickness of 10 feet. The model spans roughly 874 square miles across northern Upton County and southern Midland County (**Figure 2-1**). The chosen cell size is sufficient to capture lateral heterogeneity, as it is significantly smaller than the average spacing between wells used for petrophysical property distribution.

Table 2-2: Regional Static Model Domain Information

Coordinate System	NAD 1983		
Horizontal Datum	North American Datum 1983		
Coordinate System Units	ft US		
Zone	Texas Central Zone		
FIPSZONE	4203	**ADSZONE**	5376
Coordinate of X min	2,496,000	**Coordinate of X max**	2,645,500
Coordinate of Y min	11,388,000	**Coordinate of Y max**	11,551,000
Elevation (TVDSS) of bottom of domain	-11,992	**Elevation (TVDSS) of top of domain**	-6,110

TVDSS: True Vertical Depth Subsea

The regional model boundary was selected to encompass a representative number of wells with petrophysical logs, thereby improving constraints on porosity and permeability distributions and supporting a more robust geostatistical framework across the model domain.

A 324 square mile portion of the regional model, shown in **Figure 2-1**, was used to construct the dynamic grid for simulation. This grid retains the same cell dimensions but includes approximately 7.5 million cells. While the regional model incorporates a broad set of wells to improve petrophysical property representation, detailed structural and fault modeling was focused within the dynamic grid to better simulate flow behavior in the injection units.

Structural and stratigraphic mapping was performed by interpreting 2D seismic data and correlating formation tops (**Section 1.7 and Section 13 – Appendix D**) using digital openhole well logs, along with regional mapping and fault interpretations from published literature. Petrophysical analyses were completed on 22 wells within the regional model boundary that penetrate the top of the Woodford Formation or deeper, accounting for facies, porosity, and permeability.

Facies were estimated from log responses but were not used to constrain porosity or permeability due to the absence of core data for model validation. Available core data from the Bureau of Economic Geology in Austin include porosity, permeability, and core descriptions but lack modern electrical logs to tie these measurements to formation depth. The cores and resistivity-SP logs were acquired in the early 1950s. While facies were not used in this model to condition porosity or permeability, they were included in the initial model and are anticipated to be useful in future updates..

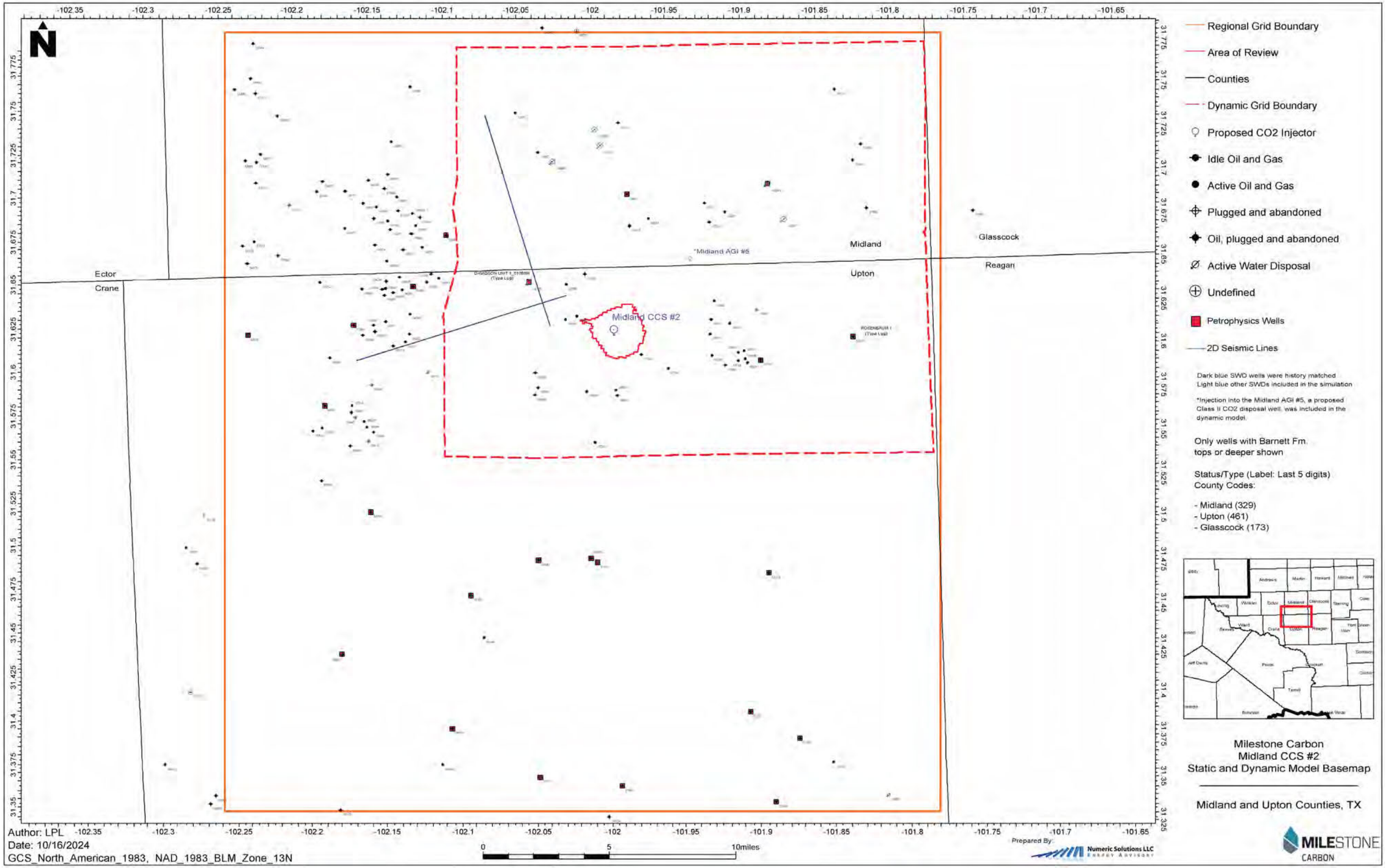

Figure 2-1: Static and Dynamic Model Basemap

Basemap of the regional static model (the regional grid) and the sector used for dynamic simulation (the dynamic grid). The AoR, the planned Midland CCS #2 Well, and wells and 2D seismic lines used to construct the static model are shown. All wells shown have well tops used to construct the structural framework model. Wells at red squares have petrophysical data (porosity and permeability) within the Injection Intervals and were used in distributing these properties. The solid red line indicates the AoR; the solid orange line indicates the regional grid boundary; the dashed red line indicates the dynamic grid boundary. Saltwater disposal wells used for history matching (dark blue) and/or with future injection volumes into the Injection Intervals (light blue) included in the dynamic model are also shown.

2.4.1 Structural Framework

The structural framework model was primarily constructed using formation tops interpreted from openhole well logs across the regional model area. These tops span from above the Barnett Formation to the base of the Ellenburger Group, encompassing all proposed confining and injection units (see type log in **Section 1.9.1**).

Additionally, two 2D seismic lines west of the AoR were reviewed, and their interpreted structural horizons were incorporated into the Model. Seismic-interpreted faults were integrated with regional faults mapped in published literature (Horne et al., 2024), and the combined dataset was used to construct the fault and structural models. All identified faults terminate below the base of the Woodford Formation (upper confining zone), within the undifferentiated Devonian Formation or deeper.

In the pillar gridding[2] methodology used for fault modeling, fault "pillars" must extend through the entire stratigraphic section; however, throw can be adjusted, or faults deactivated, for individual horizons. Fault transmissibility is then assigned for each model zone or layer to ensure faults do not exert hydraulic effects above their termination point. As a result, some figures may show faults extending through the full section, though they are deactivated where appropriate to match seismic interpretation

A total of 202 wells penetrating the Barnett Formation were reviewed. Of these, Milestone interpreted formation markers in 22 wells with digital logs (**Table 2-1**). In total, 827 formation tops were used to generate the Model's structural surfaces (see **Appendix D** for a complete list of wells and picks)

The selected stratigraphic tops served as constraint points for building stratigraphic horizons in the static geologic model. Several iterations of quality control were performed to confirm correct well elevations, verify the geologic accuracy of picks and correlations, and ensure that generated surfaces honored the selected markers at each well location **(Figure 2-2)**.

Table 2-3: Count of Well Top Control by Zone
Summary of the count of well tops for each horizon used to generate the structural framework model.

Horizon	Count
Barnett	151
Woodford	174
Devonian	171
Silurian	97
Fusselman	90
Simpson	80
Ellenburger	62
Basement	2
Total	**827**

[2] Pillar gridding, within a structured corner-point geologic model, is a method where vertical grid lines, or 'pillars,' are aligned with fault geometries across the entire stratigraphic section. These pillars ensure that the grid accurately reflects fault structures, allowing for adjustments in fault throw or deactivation at specific horizons while preserving grid consistency throughout the Model.

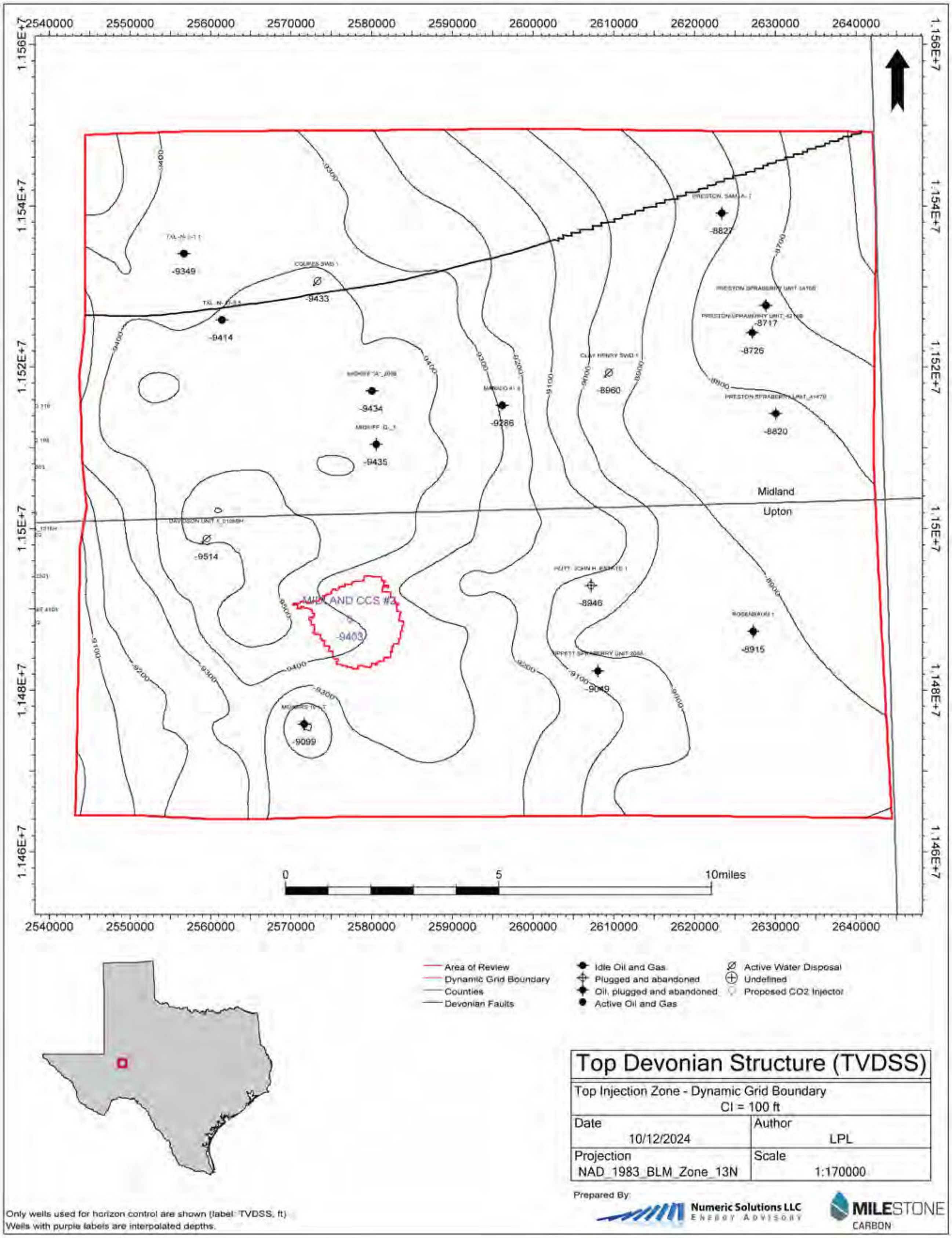

Figure 2-2: Top of Devonian Structure Map

Structure map from the static model on the top of the Devonian Formation (top storage zone). Well symbols are shown with subsea depths indicating control points used to generate the horizon.

As significantly more well penetrations exist in the Model area for the shallower horizons, the top of the Woodford, Devonian, and Fusselman formations were used as reference horizons. All other horizons were generated using conformal gridding and isochore maps (**Figure 2-3**).

The static model includes eight (8) structural horizons and seven (7) units (**Figure 2-3**):

1. Barnett
2. Woodford
3. Devonian
4. Silurian (Wristen Group)
5. Fusselman
6. Simpson
7. Ellenburger

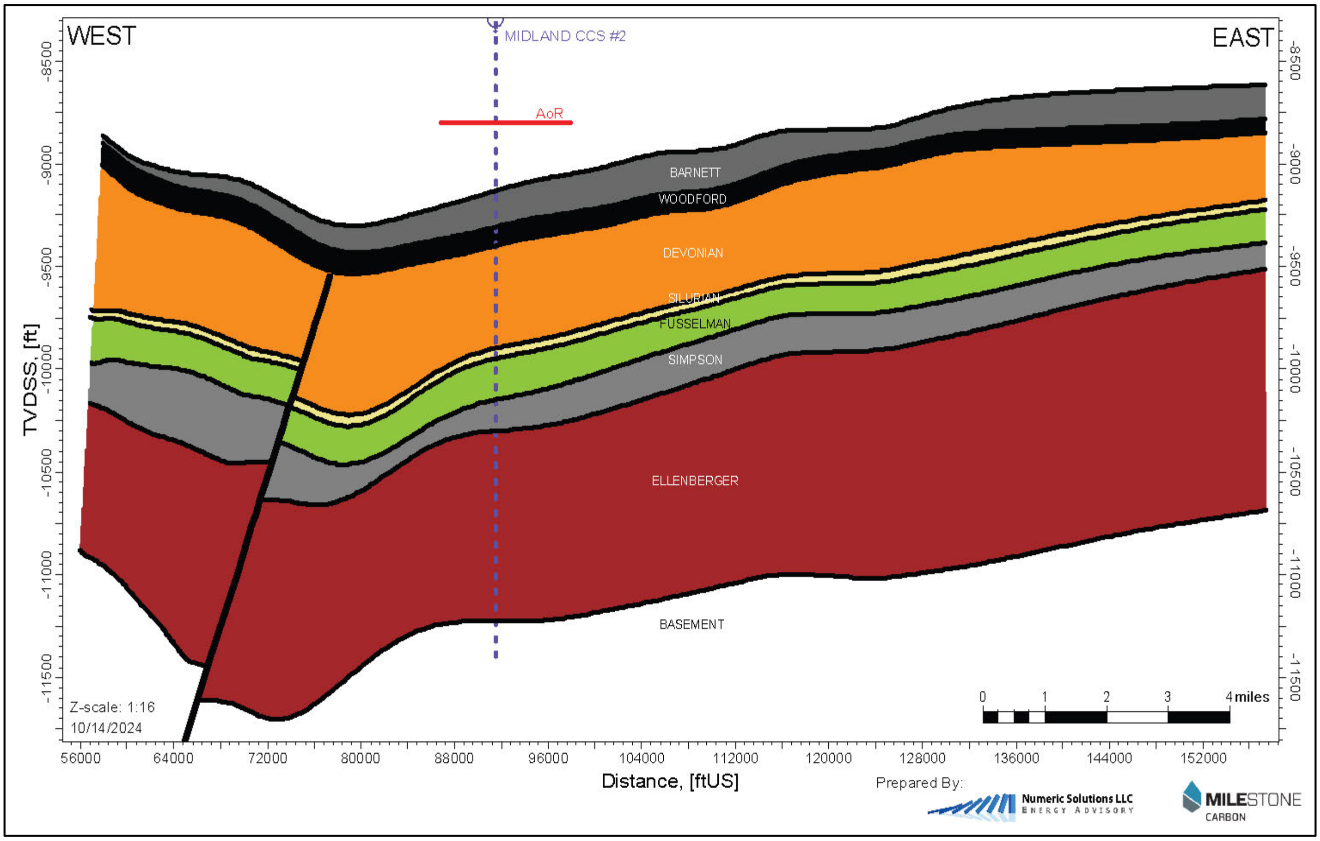

Figure 2-3: West-to-East Cross Section Through the Static Model
West-to-east cross section at the location of the Midland CCS #2 Well through the structural framework mode showing the seven units (zones) included.

2.4.2 Layering

Model layers ("K-layers") were generated using proportional layering with the number of layers assigned to each unit to maintain an average thickness of approximately 10 ft. See **Table 2-4** for the number of layers in each zone.

Table 2-4: Number of K-Layers Per Zone in the Static Model

Unit/Zone	Number of Layers
Barnett	17
Woodford	10
Devonian	52
Silurian	5
Fusselman	18
Simpson	21
Ellenburger	103
Total	**226**

2.4.3 Facies Model

As outlined in **Section 1.7.4**, four primary lithologic rock types, or facies, comprise the proposed injection and confining units across the Devonian, Silurian, Fusselman, Simpson, and Ellenburger formations. These facies include shale, chert, dolostone, and packstone (limestone) (**Table 2-5**). Facies logs (example in **Fig. 2-4**) were developed for 22 wells that penetrate the Woodford Formation, using openhole and petrophysically derived logs and the calculations described below.

Table 2-5: Facies and Facies Codes

Facies Code	Facies Type Name
0	Claystone
1	Packstone
2	Dolostone
3	Chert

Equation 1: Facies Equation Above Ellenburger (Devonian and Silurian):

$$FACIES = if(VCL > 0.19, 0, if(PEF < 4, 3, 1))$$

Equation 2: Ellenburger Facies:

$$FACIES=if(PEF < 3, 3, if(VCL > 0.2, 0, 2), if(VCL > 0.19, 0, if(PEF < 4, 3, 1))$$

Equation 3: GR Correction:

$$FACIES=if(GR > 145, 0, FACIES)$$

PEF is the photoelectric factor openhole log. VCL is the volume of clay petrophysical curve derived from the gamma ray (GR) openhole log.

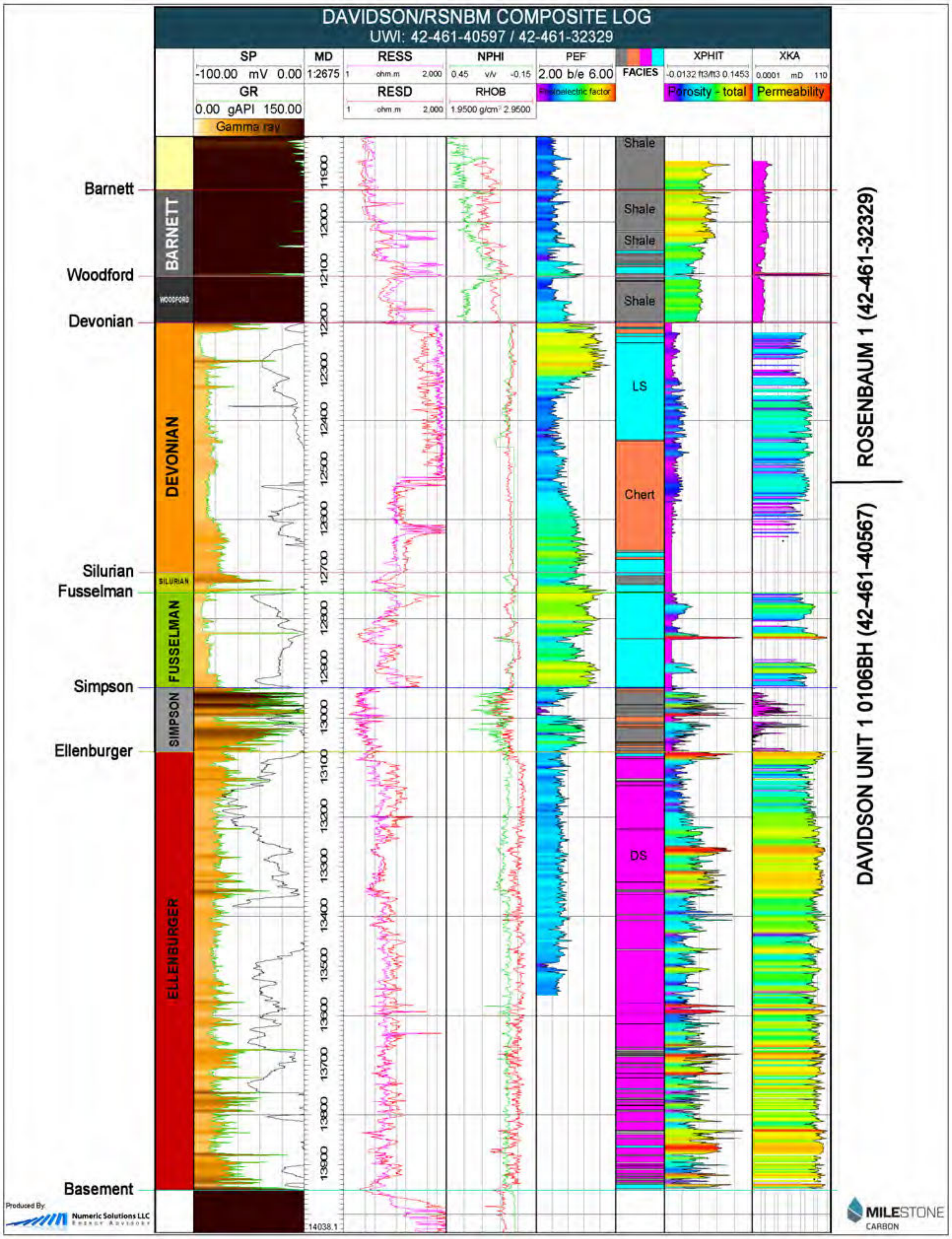

Figure 2-4: Type Well Log Model Area

Composite type well log for the Model area using wells Rosenbaum 1 (42-461-32329) and Davidson Unit 1 0106BH (42-461-40567). Key stratigraphic markers and units from above the upper confining zone to the base of the Injection Interval are shown. Track 1, on the far left, shows the stratigraphic zones. Track 2 contains the SP (Spontaneous Potential) and GR (Gamma Ray) curves. Track 3 shows the RESS (Shallow Resistivity) and RESD (Deep Resistivity) curves. Track 4 displays the NPHI (Neutron Porosity) and RHOB (Bulk Density) logs. Track 5 presents the PEF (Photoelectric Factor) curve. Track 6 shows the facies log (LS = Limestone, DS = Dolostone). Track 7 contains the XPHIT (Total Porosity) log, which was used to distribute porosity in the static model, and Track 8 shows XKA (Permeability).

Facies modeling was conducted using the following methodology based on the facies logs:

1. Well logs were upscaled into the Model by randomly selecting facies log values within each cell intersected by wells containing a facies log.

2. A vertical proportion curve (VPC) was estimated to represent the vertical distribution of the four facies within each model layer.

3. Facies were distributed throughout each Model zone using the Sequential Indicator Simulation (SIS) algorithm[3], with identical isotropic spherical variograms applied (55,000 ft horizontal and 20 ft vertical) for each facies and zone.

The resulting facies distribution for each zone within the AoR is shown in **Figure 2-5**, with east-west and north-south cross sections through the Model at the proposed Midland CCS #2 Well location provided in **Figure 2-6**. It is anticipated that once core data is acquired, relationships between facies and other properties, such as fracturing, may be identified. Therefore, Milestone incorporated facies into the Model in advance, expecting to refine its use in future updates.

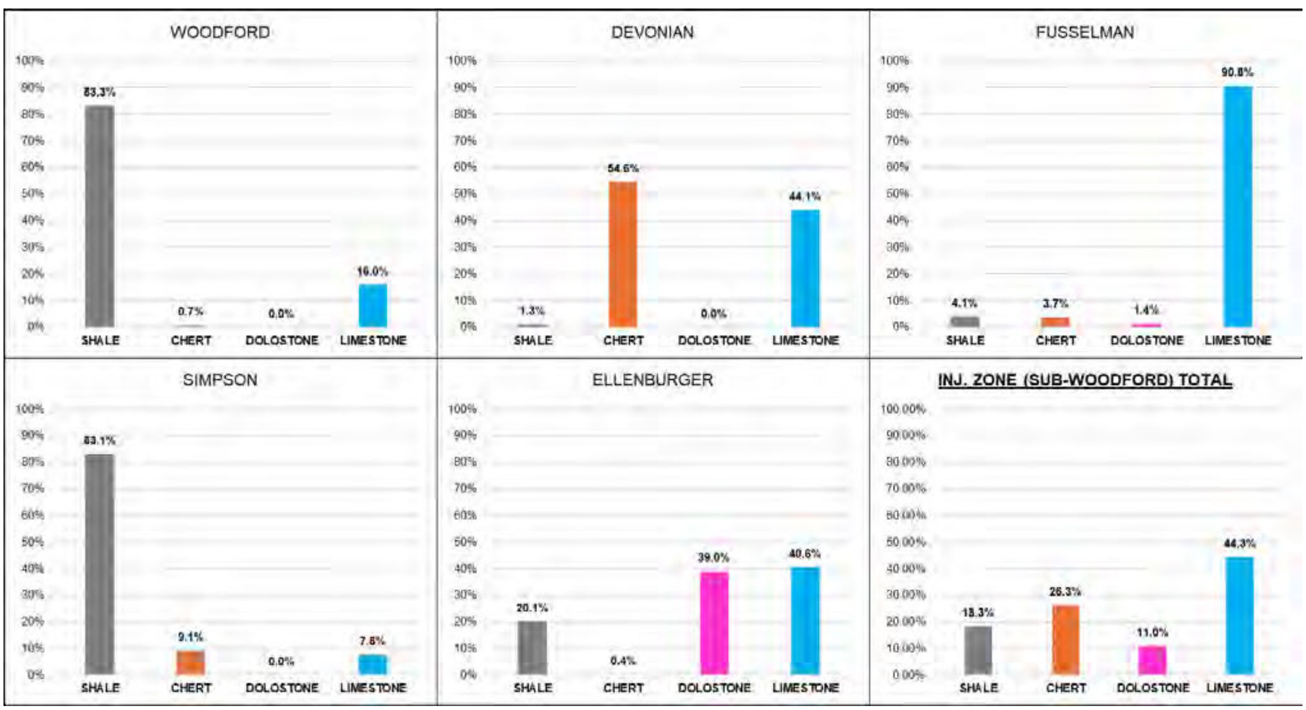

Figure 2-5: Zone Facies in AoR

Histograms show the relative proportion of each facies in each zone within the AoR. The bottom right histogram shows the relative proportion of each facies within the entire injection interval.

[3] Sequential Indicator Simulation is a variogram-based geostatistical technique developed by Alabert (1987) that stochastically populates each zone based on the input data distribution while also honoring the well data with the degree of continuity away from data controlled by the variogram via simple kriging.

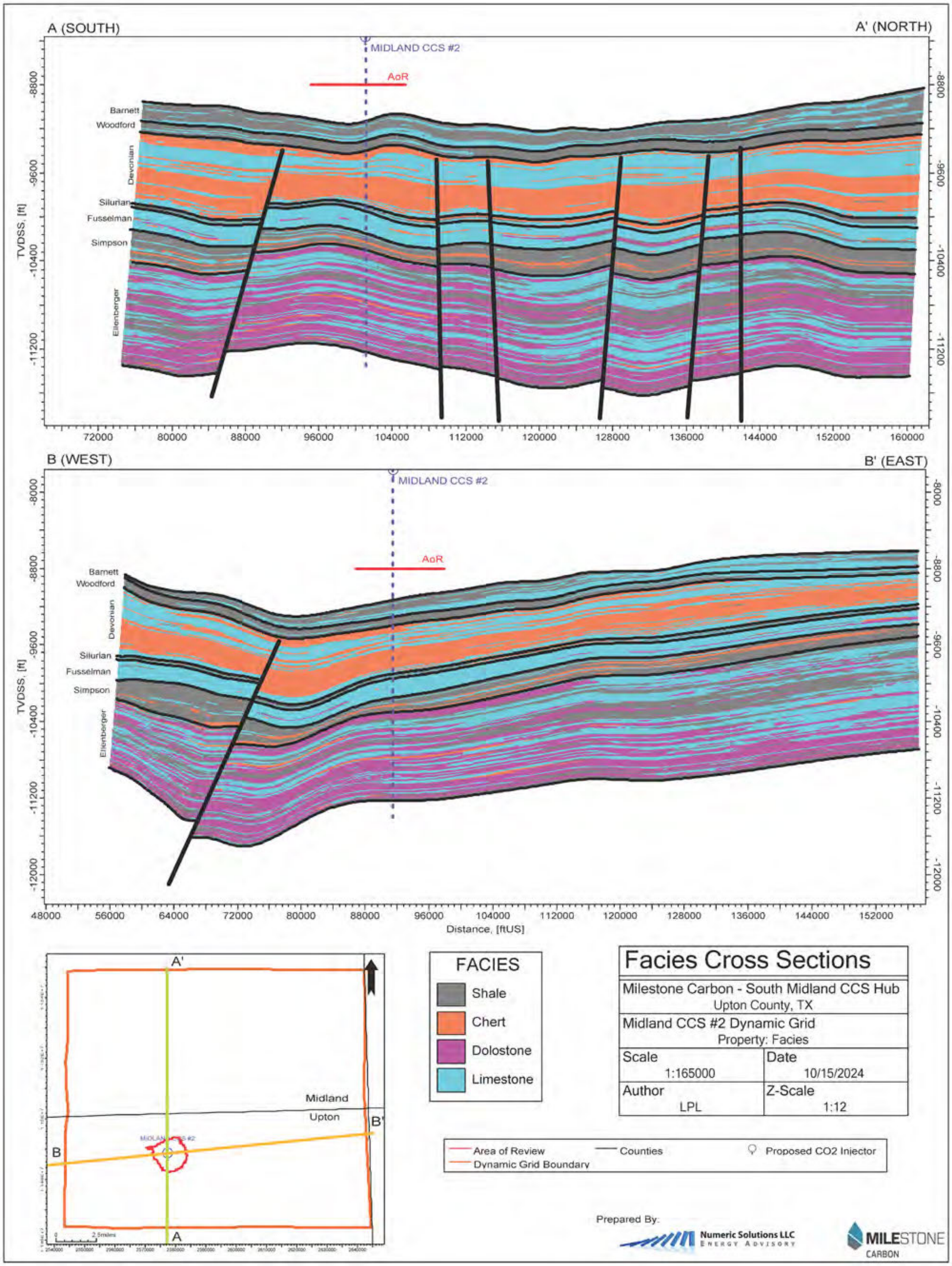

Figure 2-6: Facies Cross Sections A-A' and B-B'

South-to-north (A-A') and west-to-east (B-B') cross sections through the static geologic model showing the distribution of facies within the upper confining and injection units (12x vertical exaggeration).

2.4.4 Porosity

The total pore volume in the injection units (Devonian through Ellenburger Formations) governs the volume of CO_2 that can be stored in the reservoir and is fundamentally related to permeability. Porosity logs—including density, neutron, and sonic logs—from wells within the static model domain were used to determine the regional total porosity of the injection units. A total of twenty-two (22) wells were included, 14 of which contain sonic log data. Porosity and permeability were calculated using Milestone's petrophysical software, Geolog™.

Log analysis and interpretation suggest that porosity decreases in less brittle, and therefore less fractured, facies. The Ellenburger Group is considered the highest-quality injection unit due to its higher degree of fracturing compared to the Devonian (see **Section 1.8.1**). Milestone intends to collect and analyze core data from the stratigraphic test well prior to injection (see **Sections 5.3** and **5.4** for additional information on logging and coring plans).

Petrophysically derived porosity values (total porosity, or PHIT) from the 22 wells (see Table 2-1) were upscaled into the Model grid by sampling log values at the midpoint of each intersecting cell. This approach ensures rare high or low values are preserved, yielding a closer match to the original log distribution than averaging methods. Following upscaling, variogram analysis was conducted using Petrel's data analysis tool. The analysis did not indicate clear anisotropy, so spherical isotropic variograms were applied across all zones.

Based on data density and the variogram analysis, the following parameters were used (see Table 2-6):

- For the Barnett, Woodford, and Simpson zones: horizontal range of 150,000 ft and vertical range of 36 ft
- For the Devonian, Silurian, and Fusselman zones: horizontal range of 60,000 ft and vertical range of 36 ft
- For the Ellenburger zone: horizontal range of 85,000 ft and vertical range of 45 ft

Table 2-6: Summary of Variograms by Zone used for Porosity Modeling

Zone	Variogram Type	Horizontal Range* (ft)	Vertical Range (ft)
Barnett	Spherical	150,000	36
Woodford	Spherical	60,000	36
Devonian	Spherical	60,000	36
Silurian	Spherical	60,000	36
Fusselman	Spherical	60,000	36
Simpson	Spherical	150,000	36
Ellenburger	Spherical	150,000	45

* Isotropic

Porosity was distributed using the variograms described above, with the stochastic Gaussian Random Function Simulation (GRFS) algorithm applied to all zones. The GRFS algorithm honors well data, with spatial continuity controlled by the variogram via kriging, while also stochastically reproducing the target distribution (histogram) of the modeled petrophysical property based on log data.

Below K-layer 166 (lower Ellenburger), porosity data is available only within the dynamic model domain from well Davidson Unit 1 0106BH (API: 42-461-40597). Accordingly, all K-layers below this depth were matched to the upscaled values from the Davidson well.

Figure 2-7 provides a histogram of the input well log data, upscaled cells, and the property model for the injection unit formations. **Figure 2-8** shows the distributions by zone. **Figure 2-9** illustrates average porosity maps by zone, and **Figure 2-10** .presents two cross sections through the injection AoR displaying the porosity model.

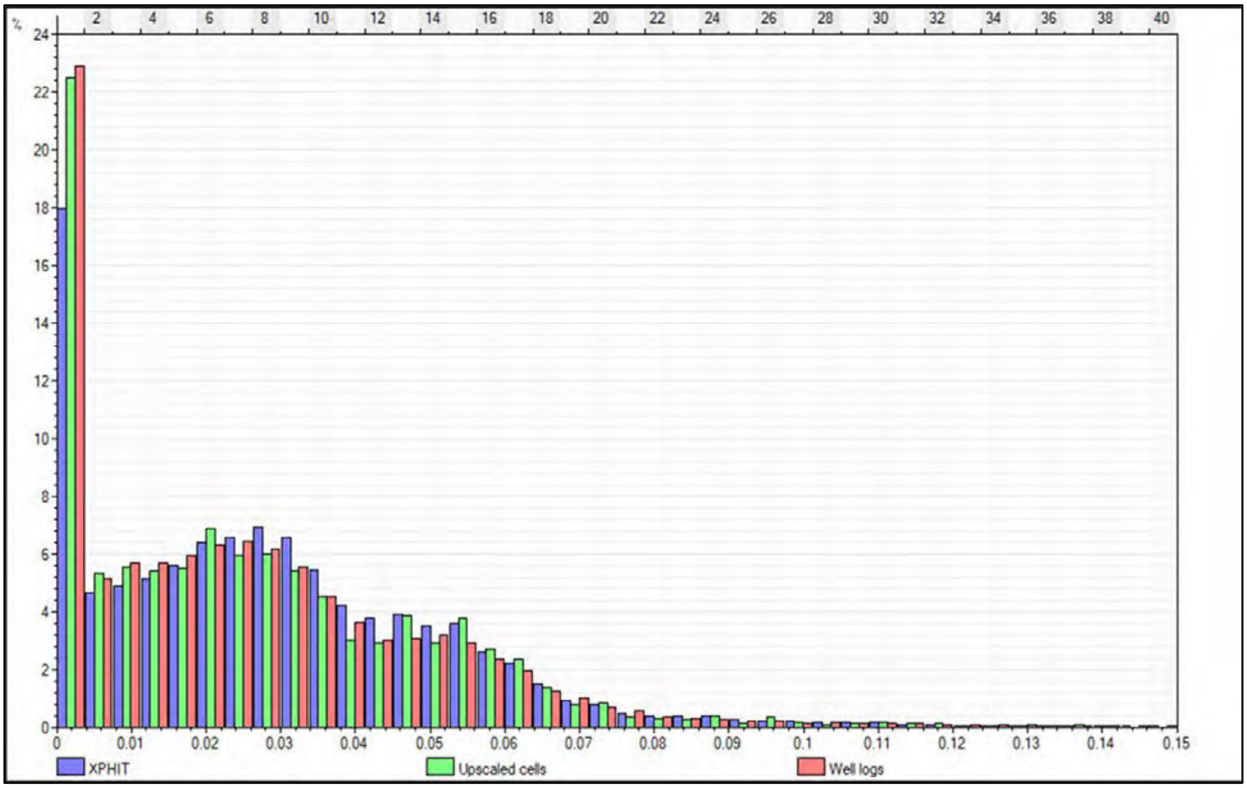

Figure 2-7: Histogram showing PHIT distribution from log data, upscaled cells, and the property model.

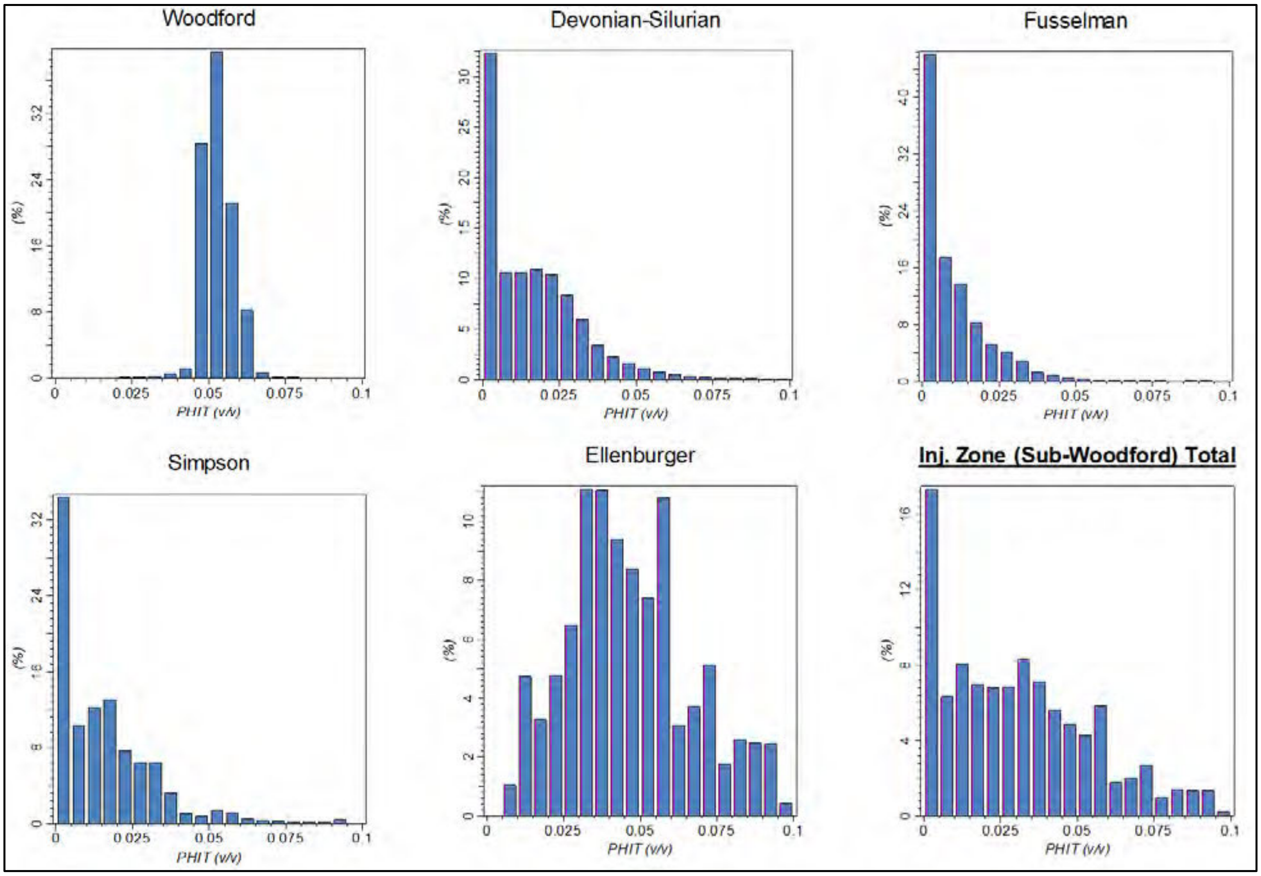

Figure 2-8: Porosity Histograms by Zone

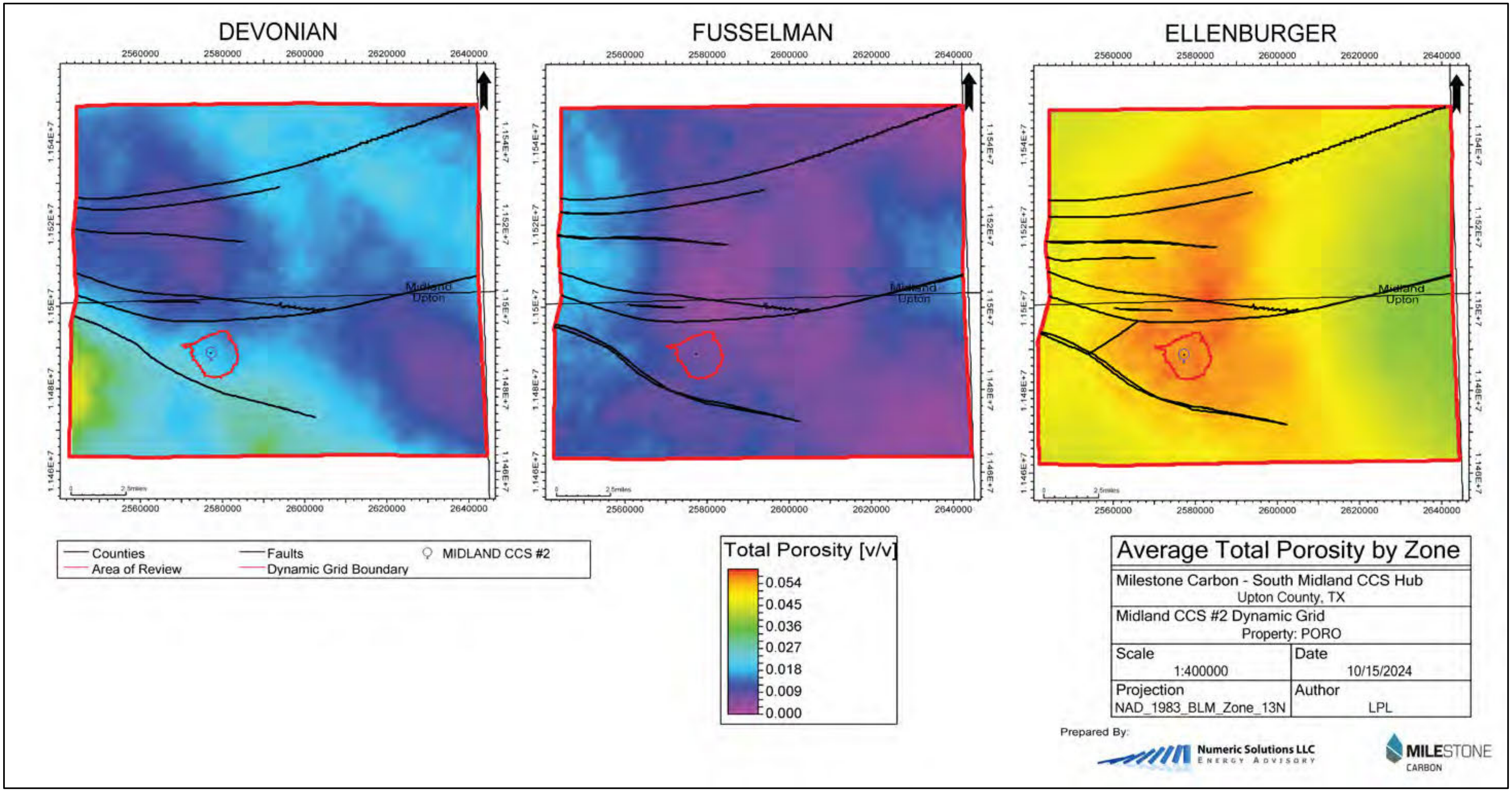

Figure 2-9: Static Model Average Total Porosity by Zone Maps
Average total porosity maps for the static model for the primary injection formations (Devonian, Fusselman, and Ellenburger).

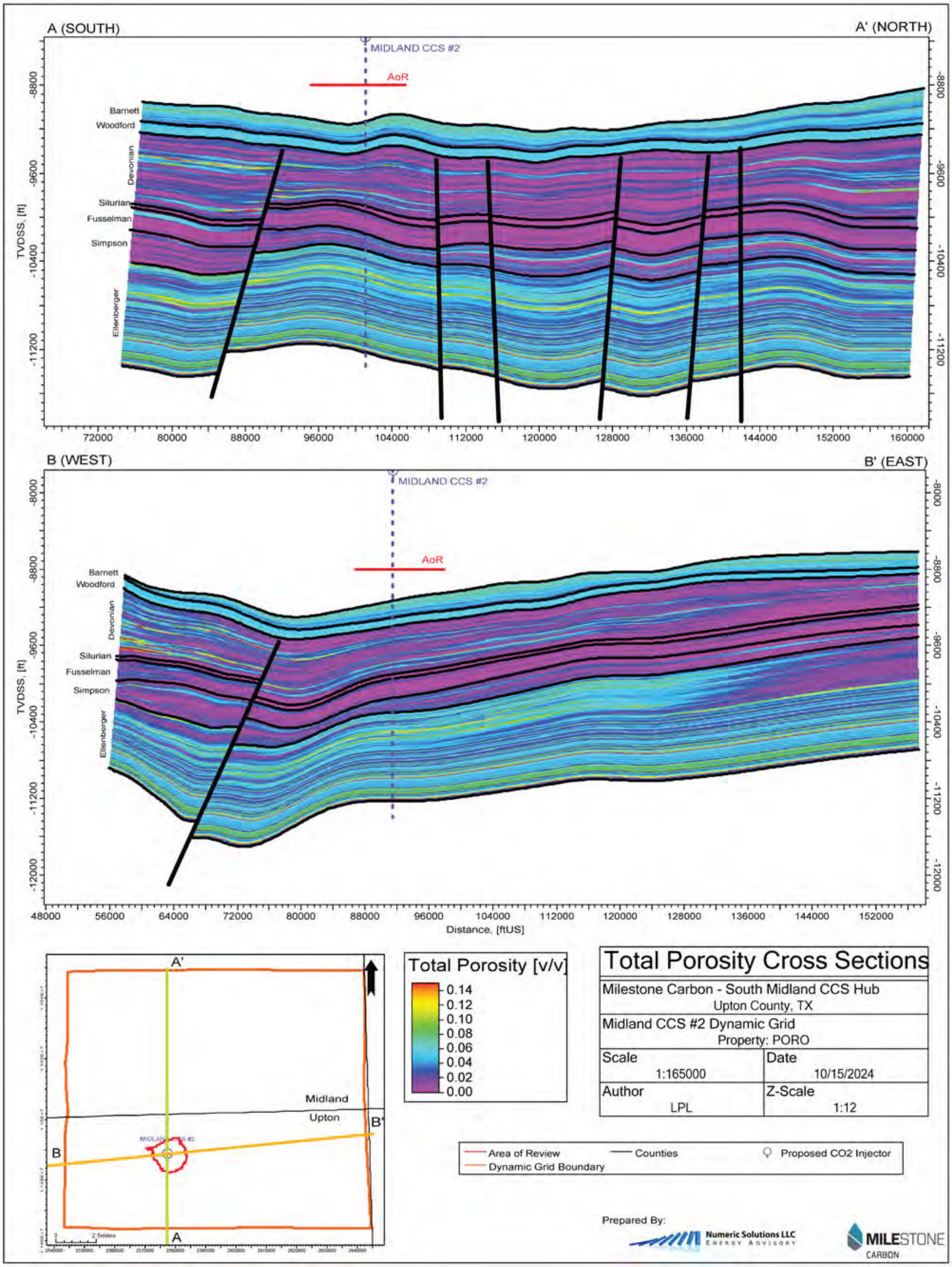

Figure 2-10: Dynamic Model Total Porosity Cross-Section Through AoR

2.4.5 Permeability

Permeability is a critical subsurface parameter in porous media that influences fluid flow rates and resulting injection pressures. Intrinsic permeability is closely related to porosity, pore size, pore structure, and the presence of natural fractures. Milestone has not yet conducted direct measurements of permeability from core samples (Kair, Kbrine) within the Model domain but plans to do so during drilling of the planned stratigraphic test well.

2.4.5.1 Permeability Calculation Methodology

Milestone estimated permeability (KA) using a function that relates porosity, clay volume, and deep resistivity to permeability in 22 openhole well logs penetrating the Devonian (see **Section 1.9.3**). These estimates represent matrix permeability across all formations in the static model and were calculated using the following algorithm based on available core data.

Equation 4: Permeability Calculation - Initial Model – Non-Shale Lithologies

$$KA = 10^{(1.3422 \times LN(PHIT) + 4.6392)}$$

Equation 5: Permeability Calculation - Initial Model – Shale Lithologies

For Shale Lithologies, $KA = 0.3 \times PHIT^2$

Equation 6: Permeability Calculation - Upwards Limit 110 mD

Limit KA = IF(KA > 110, 110, KA)

2.4.5.2 Upscaling and Distribution

The calculated, petrophysically derived permeability logs were upscaled into the Model grid by computing the arithmetic mean of log values intersecting each model cell. Permeability was then distributed throughout the Model using collocated co-kriging with the porosity model, applying an isotropic spherical variogram with the same horizontal and vertical ranges used for porosity distribution (see **Table 2-6**). he co-kriging coefficients, provided in **Table 2-7**, were set below 1 to introduce known variability into the porosity–permeability relationship.

Table 2-7: Collocated Co-Kriging Coefficients Used for Permeability Distribution

Zone	Collocated Co-Kriging Coefficient
Woodford	0.5
Devonian	0.75
Silurian	0.75
Fusselman	0.6
Simpson	0.6
Ellenburger	0.4

Figure 2-11 provides a histogram of the permeability input well log data, upscaled cells, and the permeability property model for the injection formations. **Figure 2-12** shows modeled porosity and permeability values model and average porosity and permeability values by zone at the proposed well location.

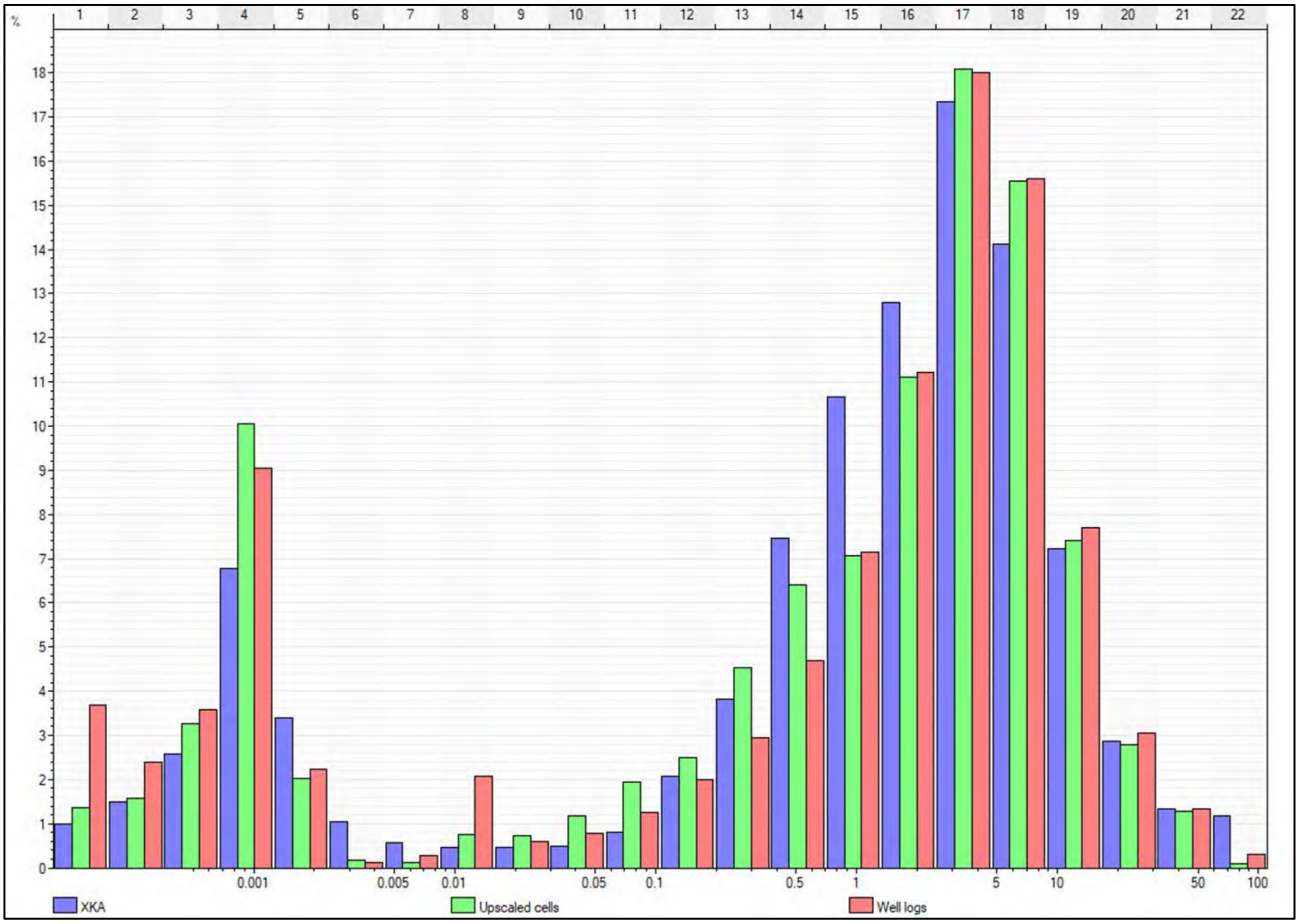

Figure 2-11: Histogram of Permeability Comparing Well Logs, Upscaled and Dynamic Model Data

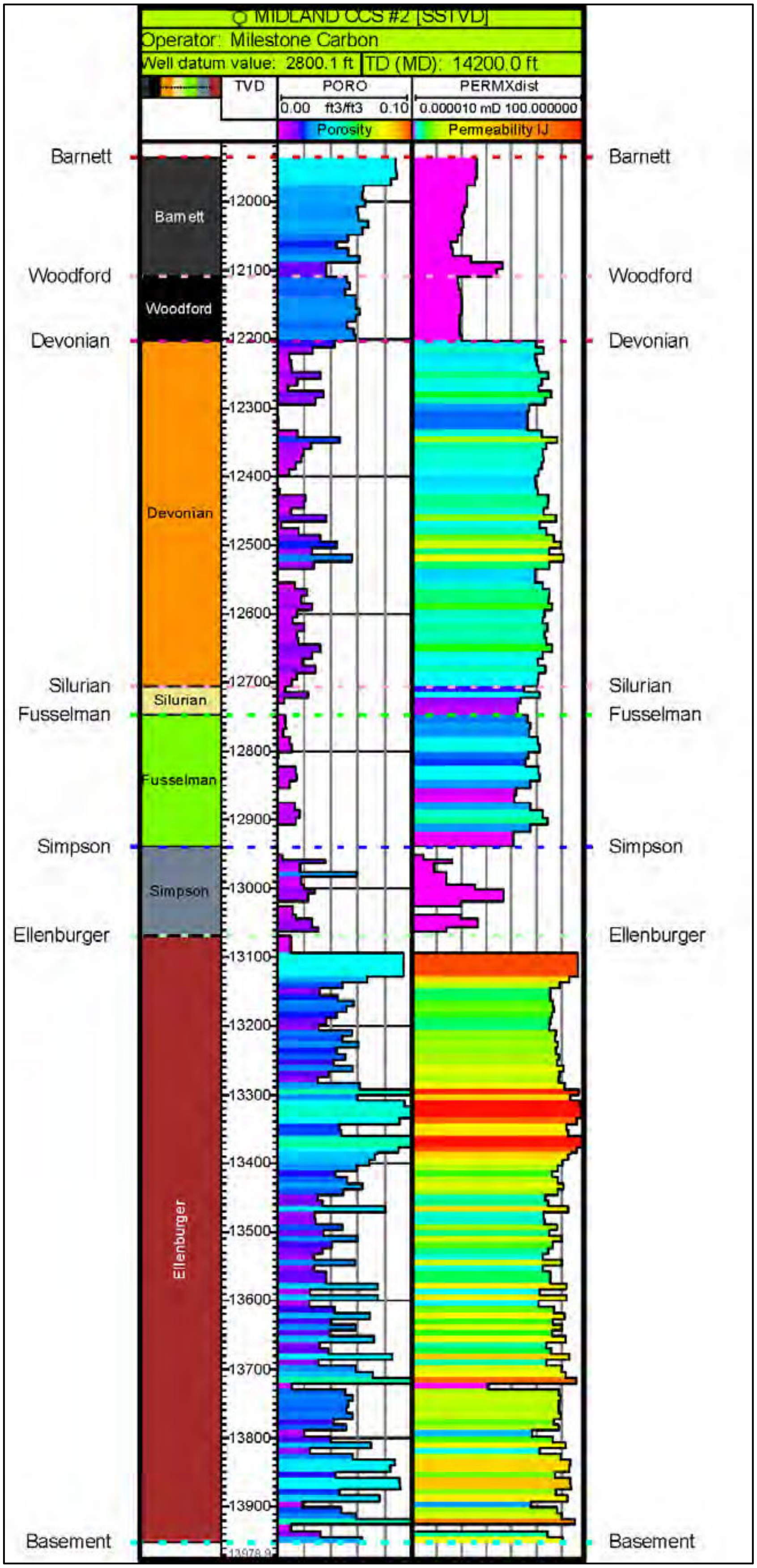

Figure 2-12: Modeled Porosity and Permeability Values at the Midland CCS #2 Well

2.4.5.3 Intrinsic and Effective Permeability

The representative ranges of values for matrix permeability and fracture permeability were sourced from the available literature (see Section 1.9.3). Matrix permeability quantifies fluid flow through the rock's pore spaces in response to pressure changes, while fracture permeability refers to flow through open fractures. In the static model, these two components were combined into a single property representing total intrinsic permeability.

Intrinsic permeability is a fundamental rock property that reflects its ability to transmit fluids through its pore network and fractures. It depends on pore size, pore structure, and the presence of fractures but is independent of the type of fluid flowing through the rock. In this model, intrinsic permeability captures the combined flow capacity of both matrix and fractures, without distinguishing their individual contributions.

Effective permeability, by contrast, is relevant within the dynamic model and represents the rock's ability to transmit a specific fluid in the presence of others—accounting for multi-phase flow conditions (e.g., oil, water, CO_2). During dynamic model calibration (history matching), effective permeability is adjusted based on observed rates and pressures. This approach enables a dual-porosity, dual-permeability system to be represented by a single permeability and porosity model. Calibration bounds effective permeability within a range of measured values, improving the accuracy of fluid flow simulation within the reservoir.

To account for vertical heterogeneity in the Model, a kv/kh ratio of 0.2 was applied to properly scale vertical permeability relative to horizontal permeability.

Average permeability maps for the Devonian, Ellenburger, and Fusselman formations are shown inn **Figure 2-14**. The Ellenburger exhibits higher intrinsic permeability compared to the overlying Devonian and Fusselman formations. No abrupt permeability changes are observed within the dynamic model or AoR.

Figure 2-15 shows north–south and east–west cross sections of intrinsic permeability through the static model (dynamic grid). Most of the higher permeability is concentrated within the lower Devonian and upper Ellenburger formations..

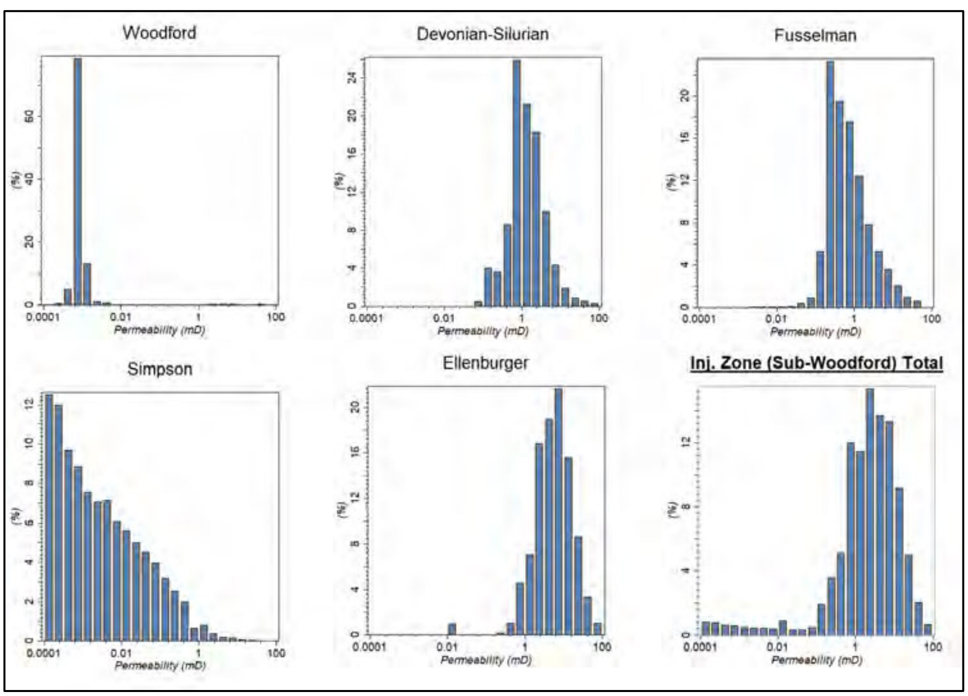

Figure 2-13: Intrinsic Permeability Histograms (IJ direction) for Each Injection and Confining Unit

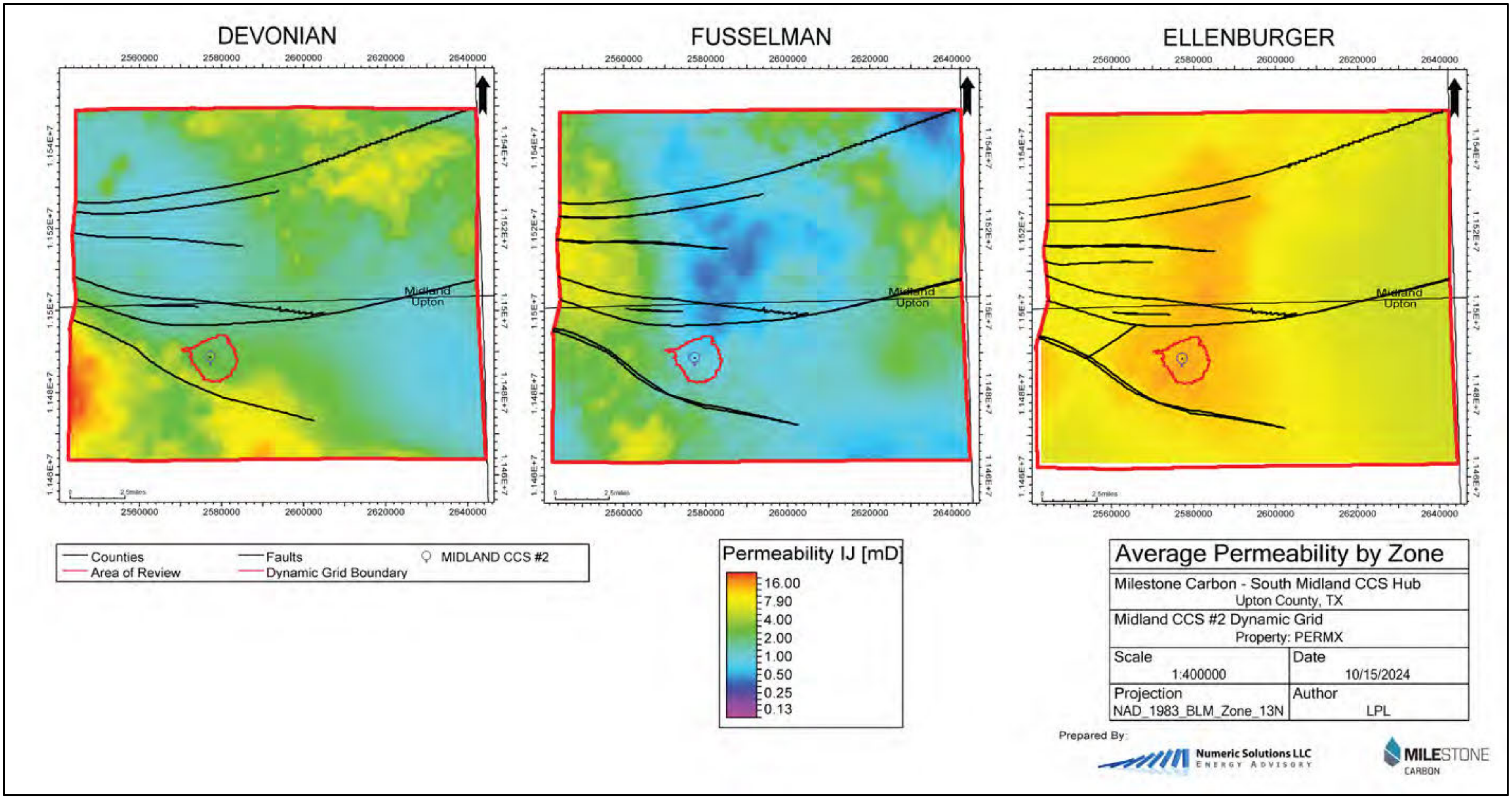

Figure 2-14: Average Intrinsic Permeability Maps for the Devonian, Fusselman, and Ellenburger Zones

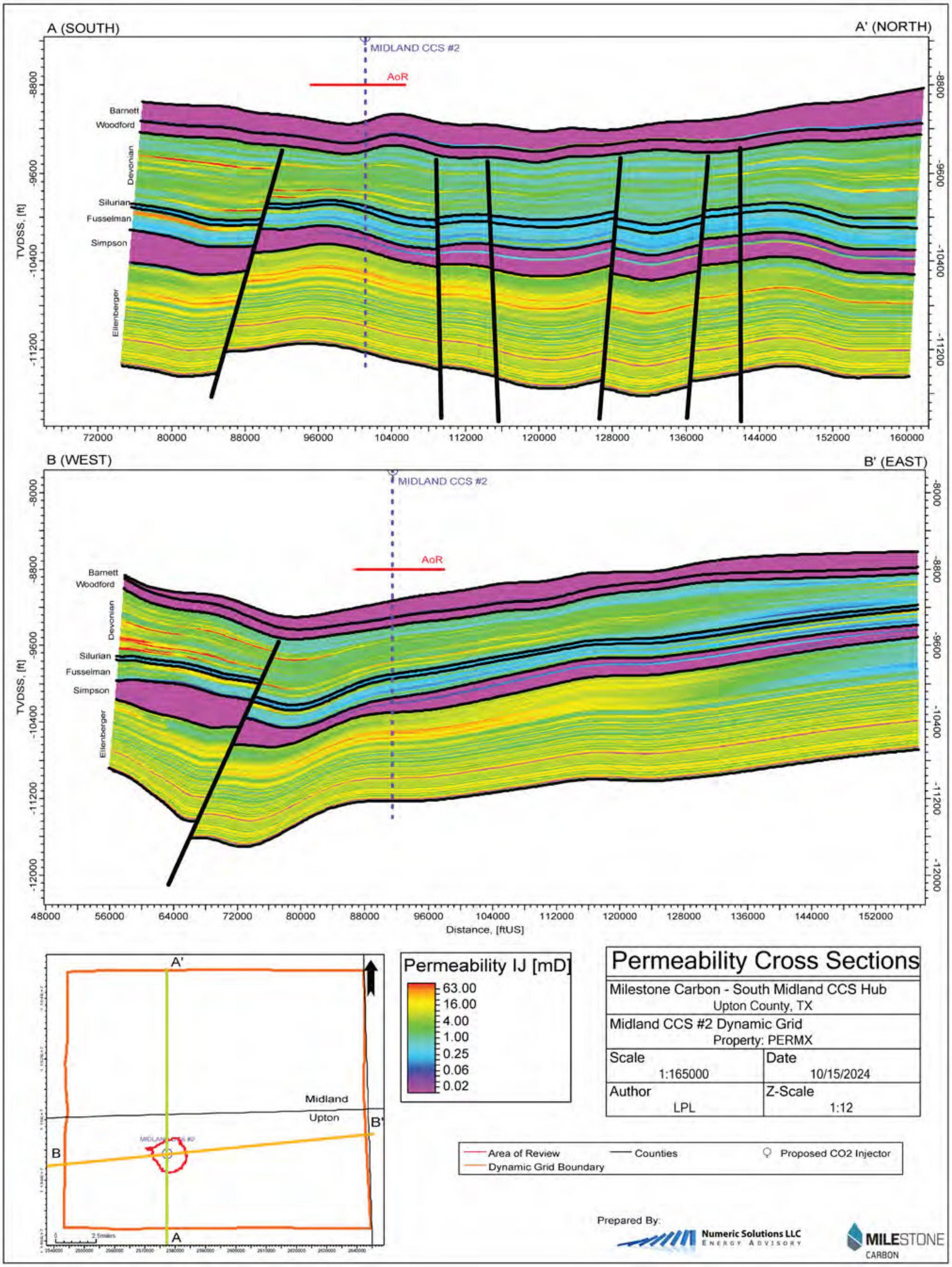

Figure 2-15: Cross Sections of Intrinsic Permeability Property (PERMX) in Static Model Across the Dynamic Grid

2.4.6 Relative Permeability and Other Rock Properties

To account for the interaction of two immiscible fluids in the pore space following the start of CO_2 injection, relative permeability curves were derived from the available literature. Two-phase relative permeability curves for water were loaded into the Model as a function of water saturation and water relative permeability. Supercritical CO_2 was loaded as a function of gas saturation and gas relative permeability.

Drainage relative permeability curves were used to model the injection period, during which non-wetting CO_2 displaces the wetting phase (formation brine). Imbibition curves were applied to simulate the reverse process, where the wetting phase displaces the non-wetting phase, typically occurring after injection ceases.

Site-specific relative permeability data will be incorporated into the revised model once obtained, pursuant to the logging and coring plans described in Sections 5.3 and 5.4.

Published data from Benson et al. (2013) were used to define initial values for relative permeability. These measurements, taken from rock samples believed to be representative of the injection units, provide a reasonable estimate based on the current understanding of the reservoir. **Figure 2-16** shows the relative permeability curves used as inputs to the dynamic simulation model, which will be further calibrated once site-specific data from the stratigraphic test well become available.

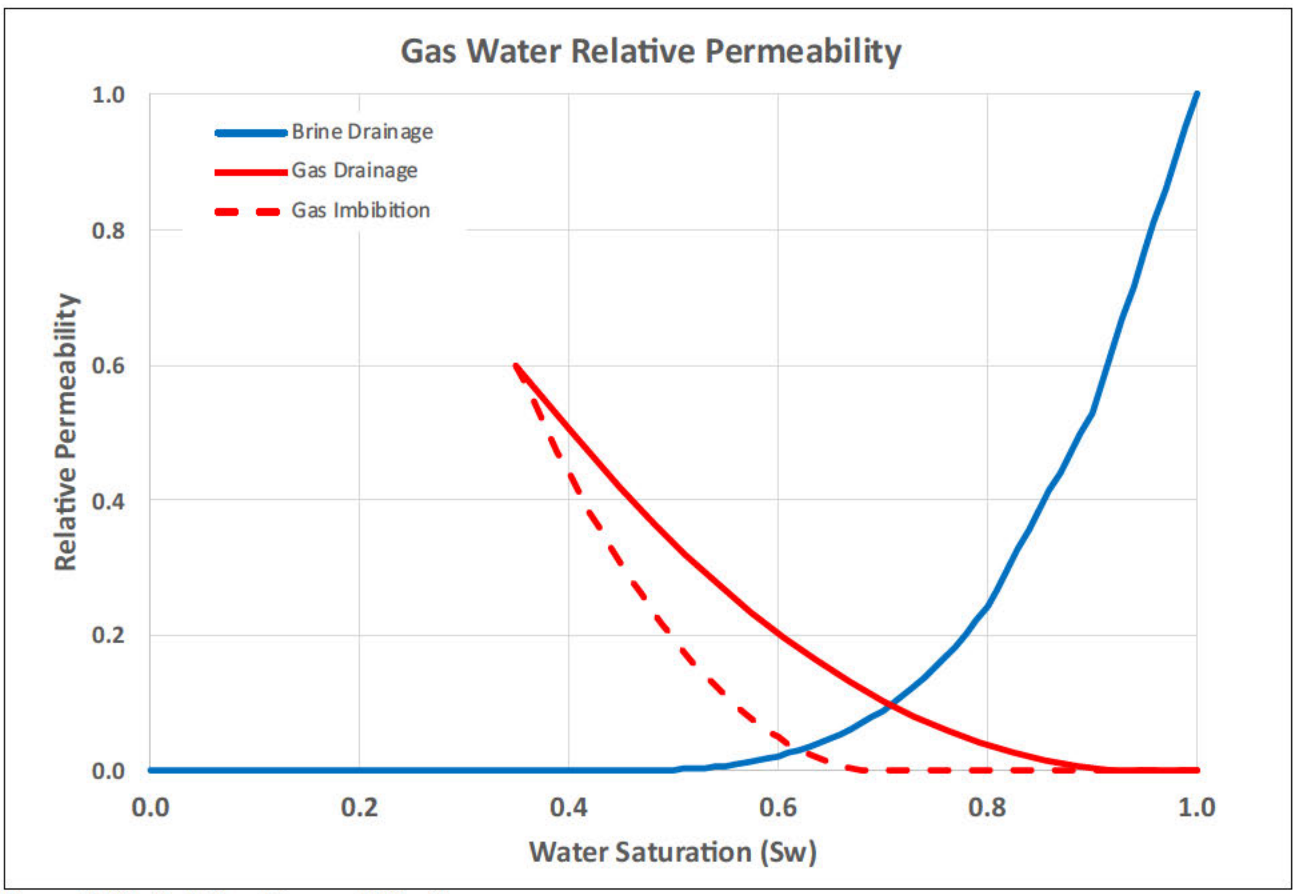

Figure 2-16: Relative Permeability Curves

2.4.7 Stress Gradients

The maximum injection pressure will not exceed ninety percent (90%) of the fracture gradient of the injection units as outlined in **Table 2-8**.

Pore pressure gradients, minimum principle stress gradients (SHmin) and 90% of SHmin for each formation can be found in **Table 2-9**. All values were calculated from wireline logs and are consistent with values reported in the available literature

Additional notes on initial reservoir pressure and stress gradients can be found in **Section 1.10**.

Table 2-8: Injection Units/Seal Stress Magnitudes

Formation	Top Depth (TVD GL, ft)	Midpoint Pore Pressure (psi)	Midpoint Minimum Horizontal Stress (SHmin) (psi)	Midpoint 90% (SHmax) (psi)
Atoka	11,503	6,093	8,857	7,971
Barnett	11,933	6,250	8,726	7,853
Woodford	12,106	6,077	9,494	8,545
Devonian (Undifferentiated)	12,200	5,612	9,209	8,288
Wristen Group (Silurian)	12,703	5,726	9,041	8,136
Fusselman	12,744	5,778	9,123	8,211
Simpson	12,936	5,850	9,548	8,593
Ellenburger	13,066	6,078	9,979	8,981
Basement	13,949			

Table 2-9: Stress and Pore Pressure Gradients by Formation

Formation	Calculated Pore Pressure Gradient (psi/ft)	Calculated SHmin Gradient (psi/ft)	90% SHmin Gradient
Atoka	0.52	0.755838	0.680254
Barnett	0.52	0.725989	0.65339
Woodford	0.5	0.781243	0.703119
Devonian (Undifferentiated)	0.45	0.738366	0.664529
Wristen Group (Silurian)	0.45	0.710537	0.639483
Fusselman	0.45	0.734395	0.639483
Simpson	0.45	0.738784	0.660956
Ellenburger	0.45	0.715395	0.664906

2.4.8 Pore Pressure

Pending direct measurements outlined in the preoperational logging and testing plans (Section 5), the pore pressure gradient has been assumed to be 0.45 psi/ft, based on data from 403 drill stem tests (DSTs) collected in offset wells. **Figure 2-17** shows a histogram of mudweights used in the region. The assumed gradient is derived from the 5th percentile (P5) of the mudweight data and corroborated by DST results. Because mudweights typically exceed actual pore pressure slightly, the mean was not used.

Pore pressure is a critical input parameter for simulation, as it directly influences the calculated plume extent and the volume of CO_2 that can be injected before nearing the fracture gradient of the formation and caprock. The assumed gradient of 0.45 psi/ft is also consistent with brine densities measured in historical water samples..

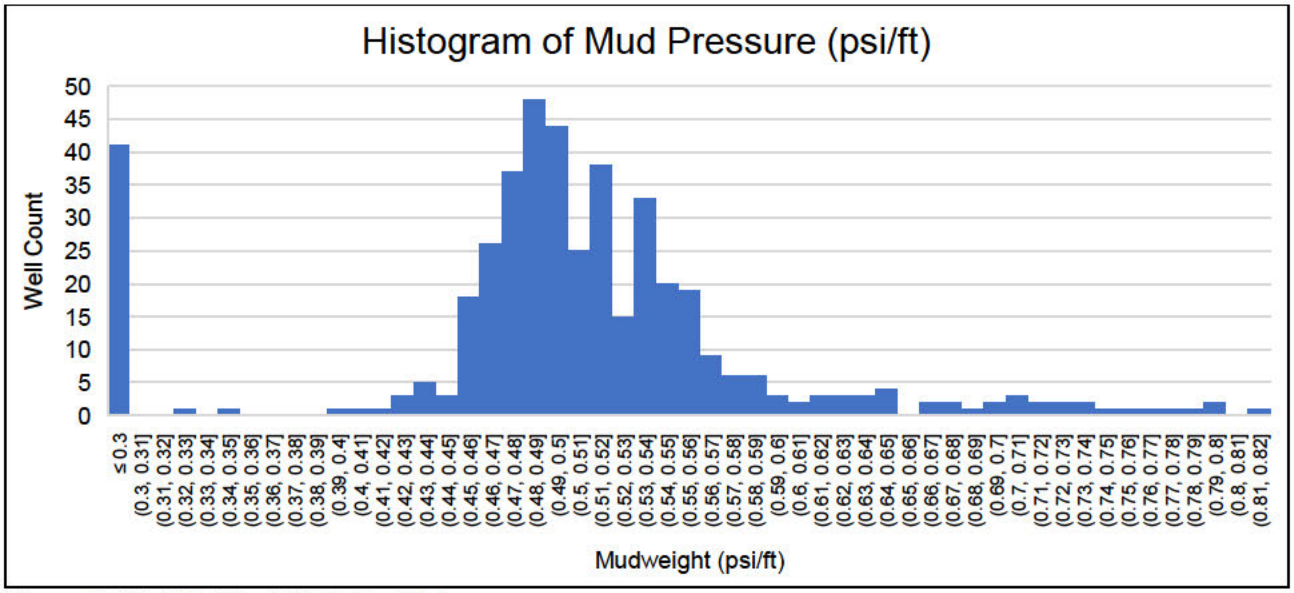

Figure 2-17: DST Mud Weights Histogram
Histogram of mudweights from drill stem tests within a 50-mi. radius of the proposed site, converted to pressure gradients. The data show that 0.49 psi/ft is the mode of the data. 403 data points are plotted on this histogram.

2.4.9 Fluid Properties

2.4.9.1 Gas Properties

To model the phase behavior of the injection stream (**Table 2-10**) and it's interaction with in-situ brine, fluid properties were simulated using the Peng and Robinson (1976) equation of state (**Equation 7** and **Equation 8**).

Table 2-10: Injected Gas Mixture by Mole Percent

Component	Mole %
CO_2	95.000
CO	0.425
H_2S	0.020
N_2	1.000
CH_4	3.555
Sum	**100.000**

Equation 7: Peng-Robinson equation of states

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)+b(V-b)}$$

Equation 8: Intermediate terms of the Peng-Robinson EOS

$$a(T) = a_c\alpha(T),$$

$$a_c = 0.45724\frac{R^2T^2}{P_c}$$

$$b = \frac{0.07780RT_c}{P_c}$$

$$\alpha(T) = \left(1 + m\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

$$m = 0.379642 + 1.48503\omega - 0.164423\omega^2 + 0.016666\omega^3$$

P = Pressure (Pa)

T = Temperature (K)

V = Molar Volume (m^3/mol)

ω = acentric factor

R = Gas constant (8.3145 J/mol-K)

Xc = Denote the critical points for respective terms

For mixtures of pure components, a binary interaction coefficient mixing rule was applied. The input parameters used in the Peng-Robinson equation of state calculation are summarized in **Table 2-11**.

Table 2-11: Peng-Robinson Equation of State Calculation Input Parameters

				Binary Interaction Coefficients				
Component	Pc (psia)	Tc (R)	Acentric fact.	CO_2	C1	H_2S	N_2	CO
CO_2	1,070.7	547.54	0.2280	0.000	0.105	0.000	0.135	0.305
C1	667.0	343.01	0.0120	0.105	0.000	0.025	0.070	0.310
N_2	501.8	227.16	0.0377	0.000	0.025	0.000	0.130	0.300
H_2S	1,300.0	672.35	0.0942	0.135	0.070	0.130	0.000	0.309
CO	513.5	239.26	0.0660	0.305	0.310	0.300	0.309	0.000

2.4.9.2 Brine Properties

The salinity of brine is 152,704 mg/L, based on extensive offset water samples (**Figure 2-18**). This corresponds to a measured brine density of 65.69 lb/ft³ at the conditions of temperatures and pressures at the top of the reservoir at the injection well. Average values throughout the reservoir have a slightly higher value of 67.4 lb/ft3 in the Model domain. The density of the aqueous phase in the model was calculated as a function of composition using the Rowe–Chou method (Rowe and Chou, 1970). See **Section 1.9.4** for additional details on water salinity. Preliminary values used in this application will be updated as future laboratory measurements become available.

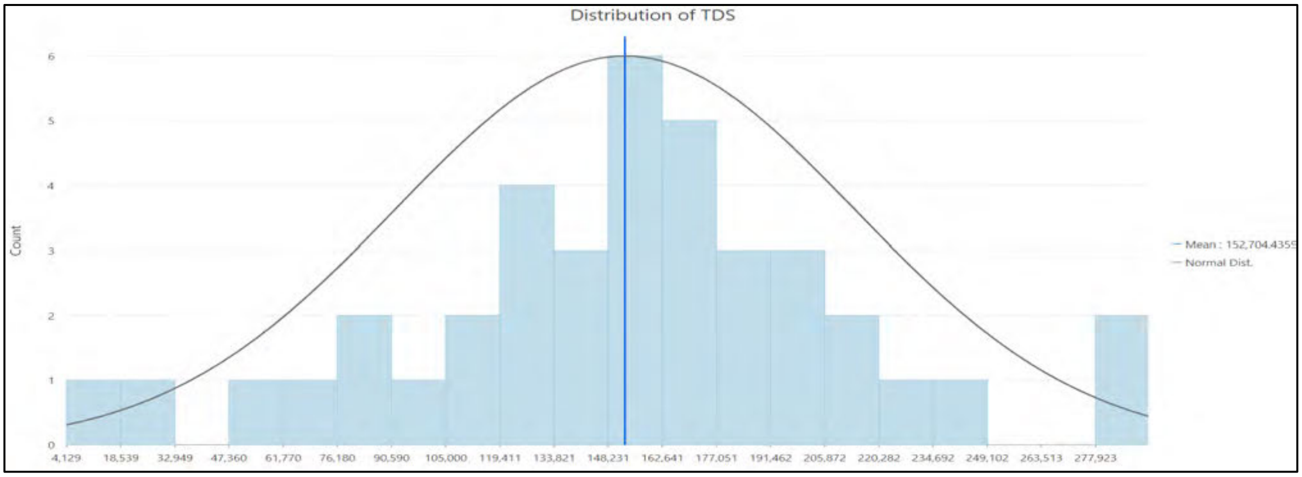

Figure 2-18: Offset Well Penetrations TDS Data

2.4.10 Injection Rate

The CO_2 injection rate was incorporated into the dynamic model as a fixed value constrained by the maximum injection pressure. The rate was programmed to decrease if pressure approached 90% of the minimum horizontal stress (SHmin).

In addition to this pressure constraint, the injection rate was modeled in two phases: a commissioning period and a full injection period. The commissioning period lasted 56 days, beginning with an initial rate of 17,530,651.46 scf/day. The rate was increased to 45,579,693.79 scf/day on Day 28 (model time: 1/29/2026) and again to the full injection rate of 54,516,444.93 scf/day on Day 56 (model time: 2/26/2026). This full rate was sustained for the remaining 11 years and 309 days of injection well operation.

2.4.11 Injection Period

The injection period is 12 years from the commencement of injection. There is a 56-day commissioning period and an 11-year, 309-day full injection period.

2.4.12 Rock Compressibility

Rock grains in the reservoir are subject to external stress from overburden accumulation and internal pressure from fluids stored in the pore space. Rock compressibility quantifies the change in rock volume in response to these forces. A value of 3.33E-06 1/psi was used for the isothermal rock compressibility of generic dolomite throughout the Model domain. This value was estimated from Xu et al. (2020) and will be confirmed through laboratory measurements obtained from the planned stratigraphic test well.

2.4.13 Boundary Conditions

The initial conditions for the dynamic model assumed a pseudo-infinite acting reservoir fully saturated with brine. To simulate this boundary condition, the grid blocks at the edge of the Model were assigned a volume multiplier of 1,000, making them 1,000 times larger than the interior grid blocks (**Figure 2-19**).

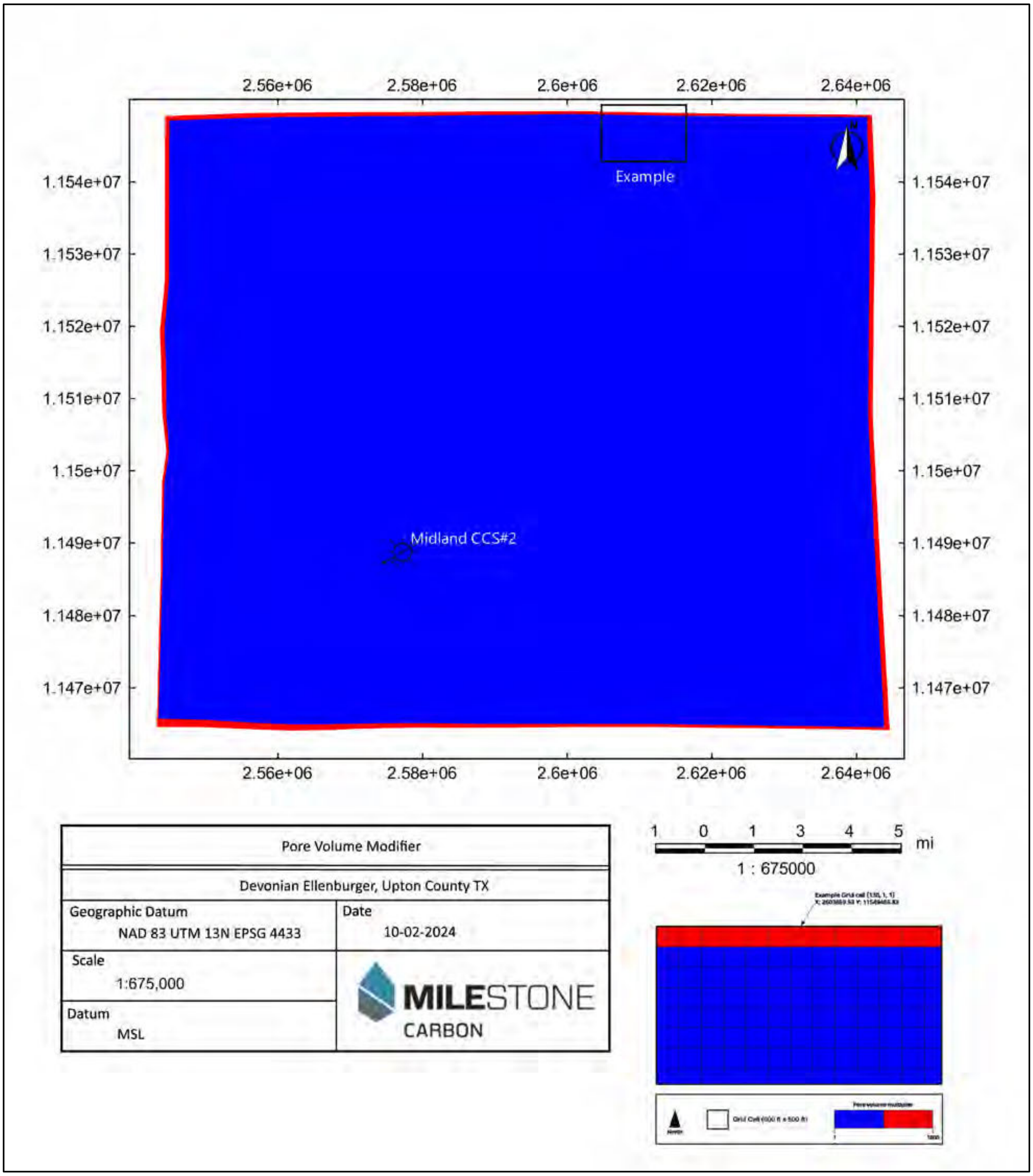

Figure 2-19: Pore Volume Modifier

Red cells represent cells with a volume multiplier of 1,000 times the volume of the grid block in the interior of the Model represented in blue.

2.4.14 Initial Conditions

Milestone used reservoir pressure, temperature, and brine salinity to initialize the Model. **Table 2-12** summarizes the general model inputs at initial reservoir conditions. The parameters outlined in **Section 2.4** were applied uniformly across a single region encompassing the full extent of the Model domain.

All runs were performed using an isothermal compositional engine. Mass transport and mineral precipitation were not considered in the initial model runs due to a lack of site-specific data. However, these effects may be incorporated and refined in future model updates following laboratory testing.

Milestone initialized the Model under the assumption that CO_2 would be injected at bottomhole conditions in a supercritical phase. Reservoir conditions were modeled to maintain CO_2 in this phase throughout the injection and post-injection periods. Storing CO_2 in a supercritical phase maximizes storage efficiency, as its density is significantly higher than in the gaseous phase—allowing more mass to be stored in an equivalent reservoir volume. Additionally, supercritical CO_2 maintains low viscosity and requires relatively low injection pressures.

Table 2-12: Summary of Initial Conditions

Parameter	Value or Range	Units	Corresponding Elevation	Data Source
Average Brine Density	67.40	lbs/ft^3	All depths	Calculated in AoR
Average Salinity	152,704	mg/L	All depths	Mean of water samples
Average Permeability Devonian	1.3742	mD	Top Devonian	Well logs
Average Permeability Fusselman	0.8	mD	Top Fusselman	Well logs
Average Permeability Ellenburger	3.7055	mD	Top Ellenburger	Well logs
Average Porosity Devonian	1.98	%	Top Devonian	Well logs
Average Porosity Fusselman	1.16	%	Top Fusselman	Well logs
Average Porosity Ellenburger	4.87	%	Top Ellenburger	Well logs
Pore Pressure Gradient	0.45	psi/ft	N/A	DST data in offset wells
Reservoir Pressure at Midland CCS #1 Top of Devonian	5,490	psi	Top of Devonian	Calculated
Frac Gradient Devonian	0.7384	psi/ft	Devonian	Calculated (see section 1.10)
Frac Gradient Fusselman	0.7344	psi/ft	Fusselman	Calculated (see section 1.10)
Frac Gradient Ellenburger	0.7154	psi/ft	Ellenburger	Calculated (see section 1.10)
Temperature Gradient	0.0103	°F/ft	N/A	Well logs
Avg. Reservoir Temp. Ellenburger	194.6	°F	Top Ellenburger	Well logs
Avg. Reservoir Temp. Devonian	185.7	°F	Top Devonian	Well logs
Surface Temperature	60.0	°F	Surface	Assumed
CO_2 Phase	Supercritical		N/A	Calculated
Average Brine Viscosity	0.329	cp	All depths	Calculated in AoR
Rock Compressibility	3.33E-6	1/psi	All depths	Well logs/Newman
Fault Transmissibility	0.01	-	All depths	Assumed

2.4.15 Potential for Future Updates

Both the static geologic model and dynamic reservoir simulation model serve as baselines to which measured laboratory data and field observations can be added. In addition to incorporating new field and laboratory data, the Models can be systematically updated with each measurement to quantify incremental changes across the static model of the South Midland Facility project area.

Once initialized with updated parameters, the Model can be history-matched to recorded injection pressures and volumes, allowing further refinement of model parameters to align with observed field conditions.

2.5 Dynamic Model Geometry and Properties

The upscaled static geologic model was used as input for the dynamic reservoir simulation model, which was designed to simulate the CO_2 plume extent and pressure front resulting from the injection of supercritical CO_2 into the injection units.

The dynamic model consists of 226 layers across the injection units and approximately 7.5 million active cells. Each grid block has an area of 500 by 500 ft, with the model covering an aerial extent of 312 square miles. Grid scaling is consistent across all vectors (IJK). A single Class VI CO_2 injection well was included in the model to simulate the behavior of the plume and pressure front during injection[4].

The model shown in **Figure 2-20** provides the most complete representation of the dynamic reservoir model and the parameters required to simulate subsurface behavior. The figure includes a 3D view of the Model and the location of the Midland CCS #2 Well. Specifications for the Model domain are summarized in **Table 2-13**.

Table 2-13: Dynamic Model Domain Information

Coordinate System	NAD 1983		
Horizontal Datum	North American Datum 1983		
Coordinate System Units	ft US		
Zone	Texas Central Zone		
FIPSZONE	4203	**ADSZONE**	5376
Coordinate of X min	2,541,496	**Coordinate of X max**	2,644,471
Coordinate of Y min	11,461,870	**Coordinate of Y max**	11,549,714
Elevation (TVDSS) of bottom of domain	-11,996	**Elevation (TVDSS) of top of domain**	-8,367

TVDSS: Subsea True Vertical Depth

[4] Injection into the Midland AGI #5, a proposed Class II CO2 disposal well, was also included in the dynamic model.

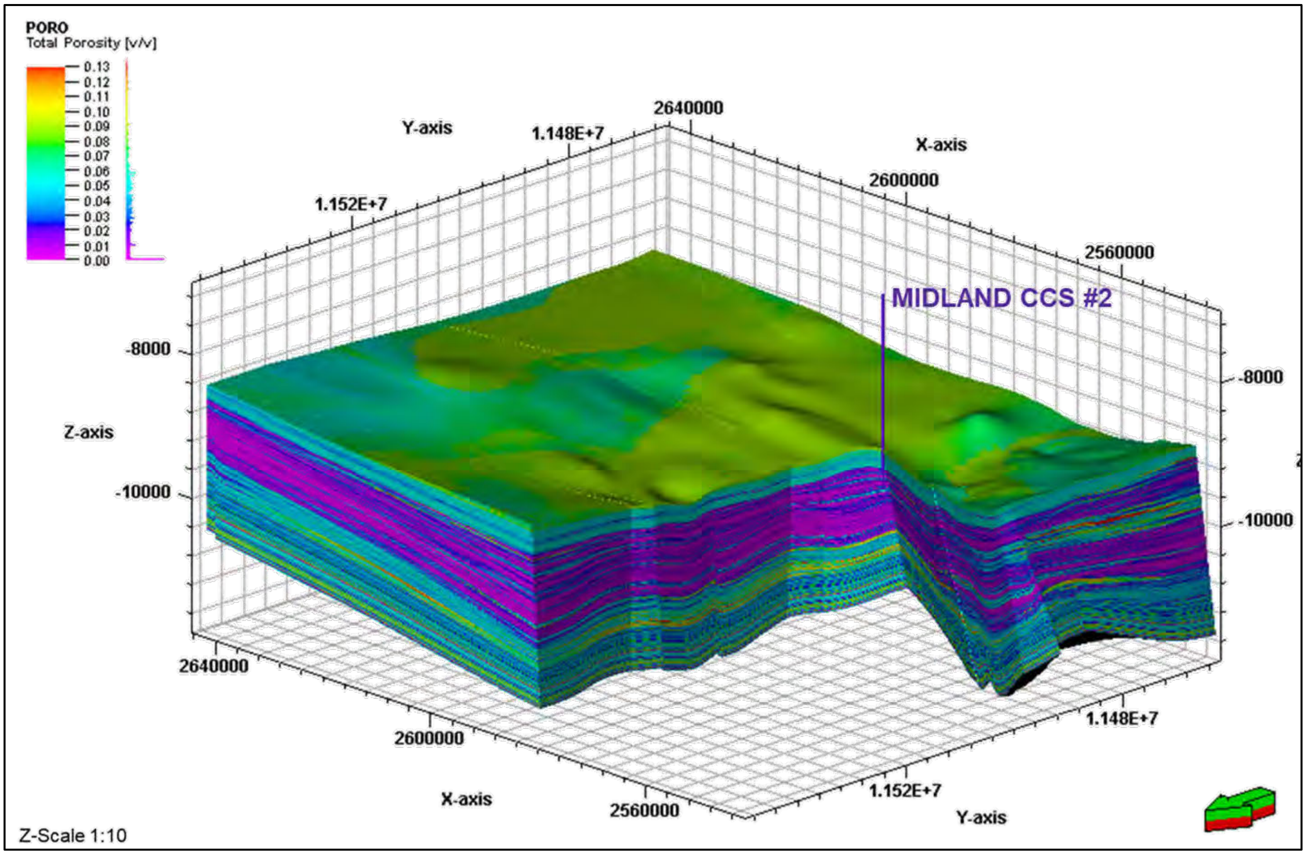

Figure 2-20: Midland CCS #2 Well 3D Dynamic Model Grid
3D view of dynamic model grid and placement of the Midland CCS #2 Well. The Midland CCS #2 Well is positioned at the center of the cutaway. Color fill is the porosity of the reservoir.

2.6 Computational Modeling Results

2.6.1 Predictions of System Behavior

Milestone generated a dynamic reservoir model to delineate the CO_2 plume and characterize the extent and geometry of the Area of Review (AoR). The model also identified the extent of the pressure disturbance and the point at which pressure changes and diffusion become negligible. In addition to calculating the plume extent and AoR (**Table 2-14**), the simulation demonstrates the optimized storage capacity of the reservoir. The cumulative volume of CO_2 injected during the simulation was 223.1 Bcf, or 11.8 million tonnes, at standard conditions (60°F and 1 atm).

The extent of the plume at the end of the injection period (modeled year 2039, after 12 years of injection) is shown in **Figure 2-21.** After injection ceases, the plume continues to expand gradually in all directions, though post-injection growth is limited (**Table 2-14**). A drop in bottomhole pressure is observed at the end of injection, as CO_2 begins to diffuse into the surrounding pore space.

The temporal progression of the CO_2 plume is shown in map view in **Figure 2-21**. By model year 2089 (50 years post-injection), the plume reaches a horizontal radius of approximately 11,823 ft. At this time, the gas saturation at the outer edge of the plume is approximately 2.0%.

Table 2-14: Change in Plume Dimensions Through Time

Year	Plume Area (ft^3)	Avg Plume Radius (ft)	Percent Change In Area Per Year (%)
2039	66,408,131	4,598	-
2041	70,473,355	4,736	5.77%
2045	73,856,303	4,849	2.23%
2055	80,906,482	5,075	1.76%
2065	85,483,412	5,216	2.76%
2075	88,041,944	5,294	0.71%
2089	92,533,590	5,427	0.06%
Total Change	**+26,125,459**	**+830**	**+28.2%**

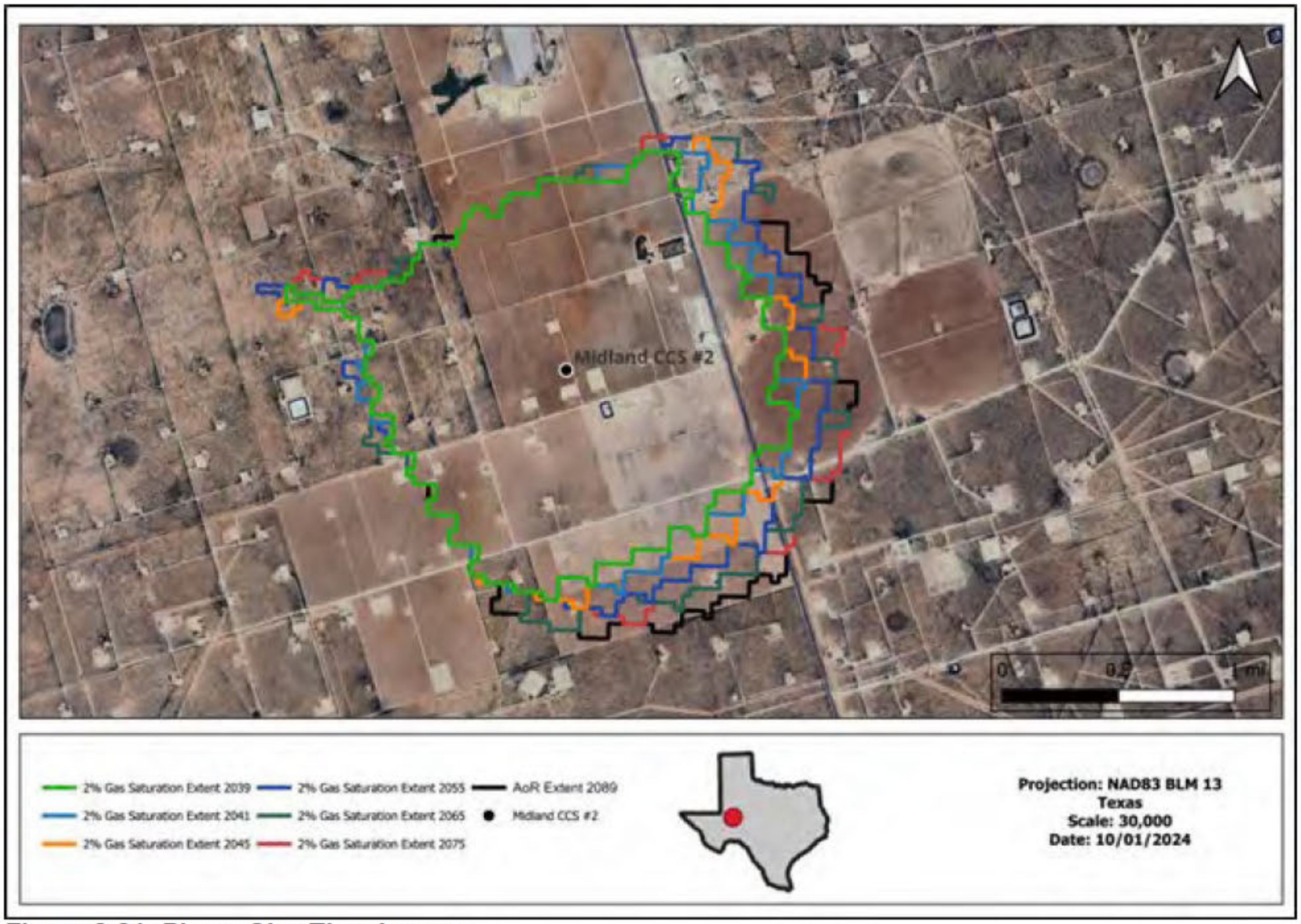

Figure 2-21: Plume Size Time Lapses
"Cooler colors" (i.e. dark green/dark red) are late time, "hotter colors" (i.e. green/orange) are early time

Figure 2-23 shows the plume in cross-sectional view. The plume varies in width vertically based on the porosity and permeability in each formation of the injection unit of the reservoir. The Model shows that most of the supercritical CO_2 (sc-CO_2) migrates into the upper Ellenburger and middle-upper Devonian, following areas of higher permeability and fracturing, and continues to expand horizontally under the Simpson Formation and the packstones of the upper Devonian.

After injection ceases in model year 2039, the Model continues to simulate plume expansion, as shown in **Figure 2-23** and **Figure 2-24**. Post-injection plume growth is minimal—less than 1% change per year and less than 830 ft of total expansion between 2039 and 2089 (**Figure 2-22** and **Table 2-14**). The Ellenburger Formation, due to its higher permeability, receives a larger proportion of the injected supercritical CO_2 **Figure 2-23**. Most post-injection migration occurs in the vertical direction, with CO_2 occupying additional pore space in the Devonian. No injectate is observed to migrate through the overlying Woodford Shale or Barnett Shale.

After model year 2065, the incremental change in plume area remains below 1% per year (**Table 2-14**), corresponding to an average lateral expansion of approximately 105 ft per year. This limited movement indicates the plume has reached a quasi-stable state, significantly reducing the risk of upward migration to the surface or into underground sources of drinking water.

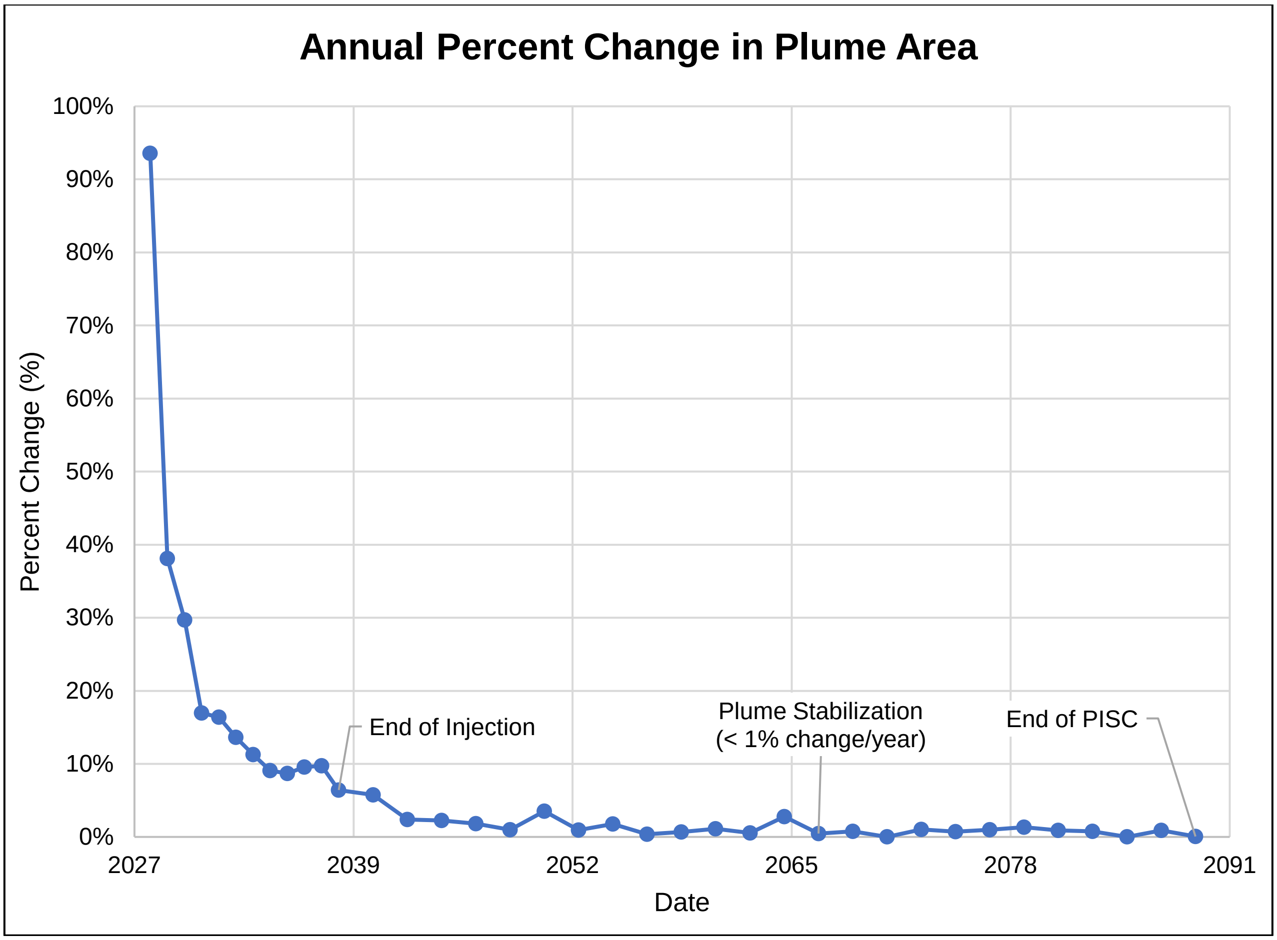

Figure 2-22: Annual Percent Change in Plume Area Through the End of PISC

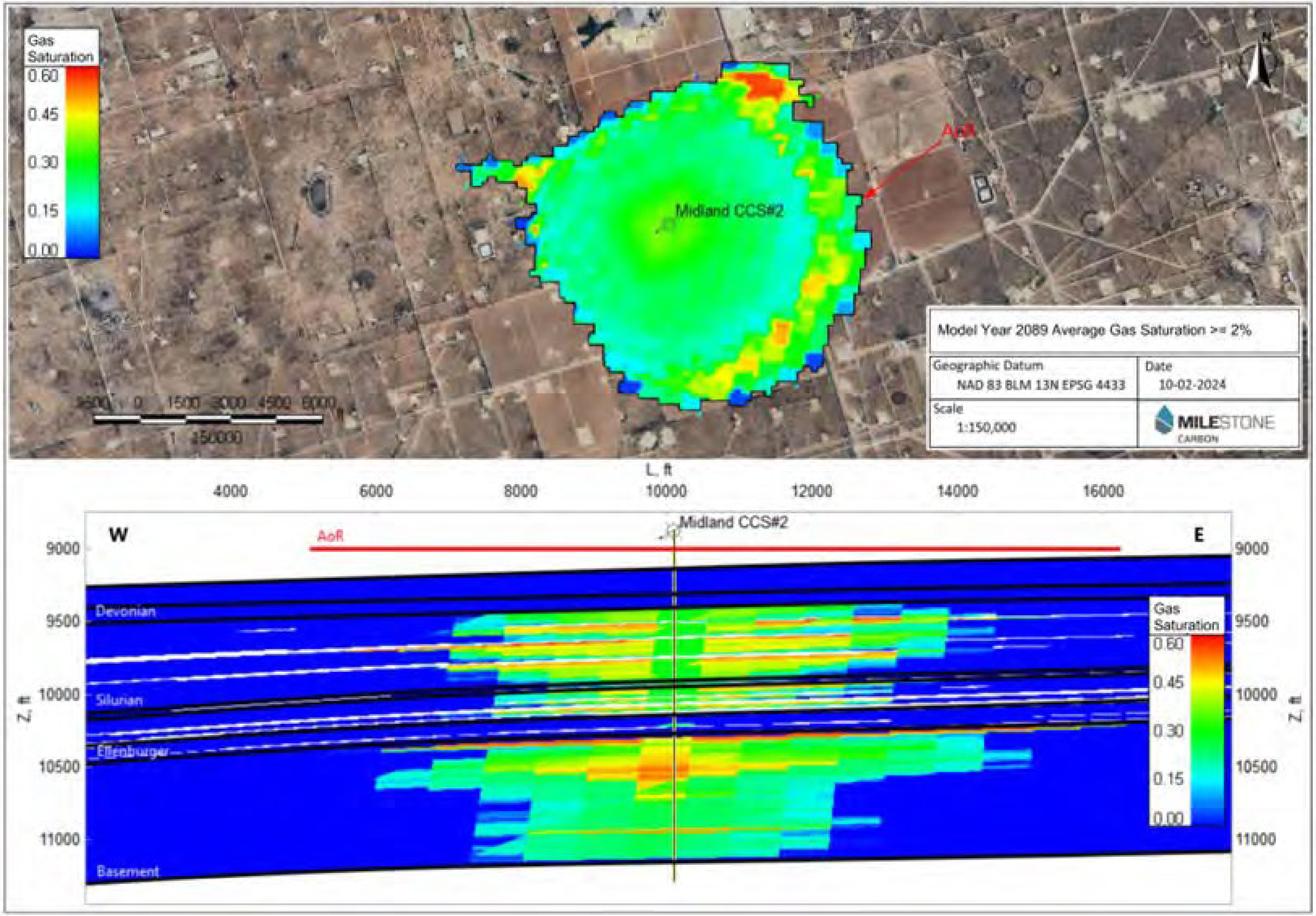

Figure 2-23: Modeled sc-CO_2 Saturation in Model Year 2089

Modeled sc-CO_2 saturation in year 2089 or 50-years post-injection. Top: aerial view; Bottom: cross-sectional view. sc-CO_2 saturation shown in the aerial view is the vertical average saturation for the entire system. Red outline encompasses any sc-CO_2 saturation in any cell greater than 2%.

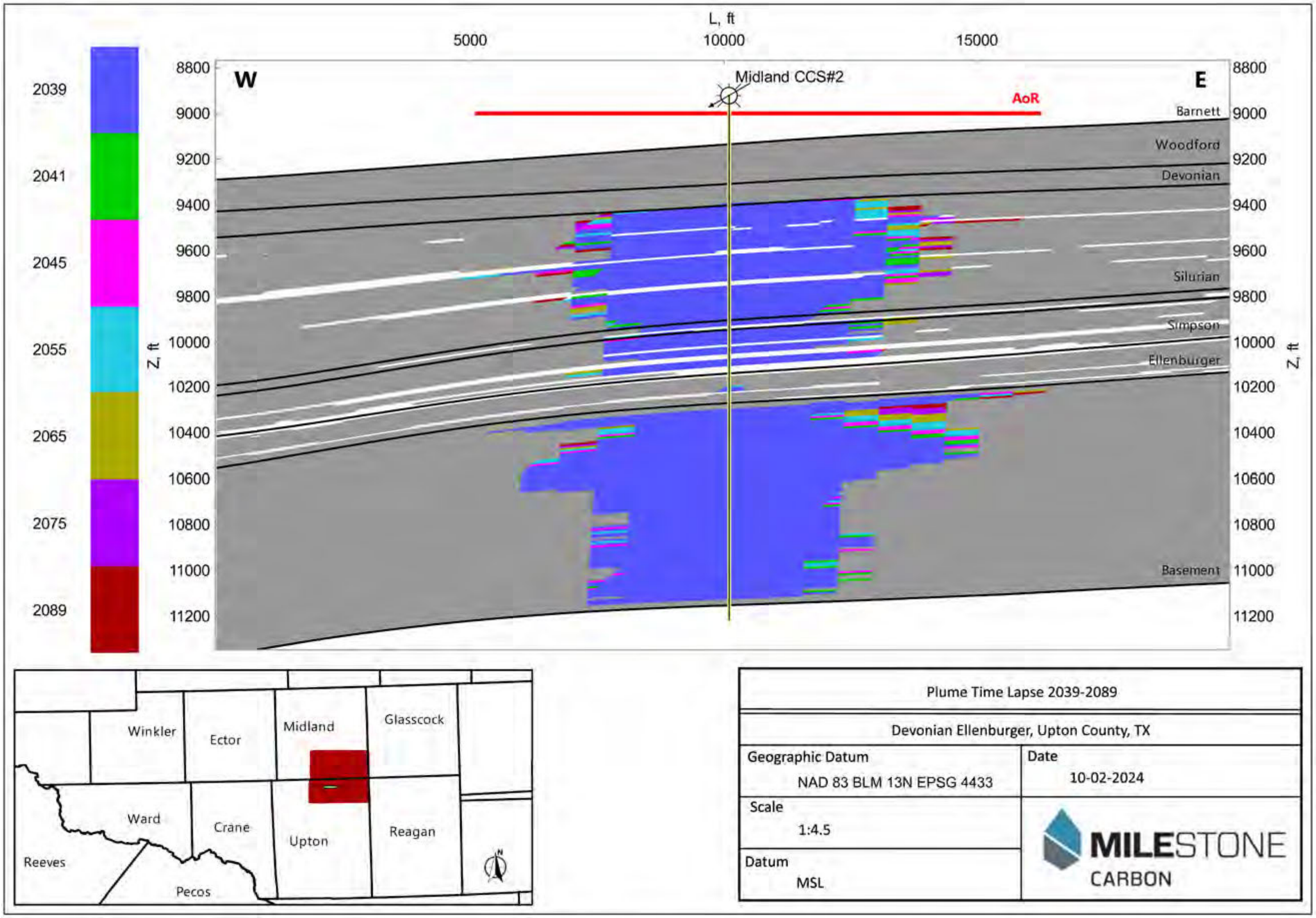

Figure 2-24: CO_2 Saturation Cross Section

Cross-section view of sc-CO_2 saturation from west to east showing the migration of CO_2 over time post-injection. Red is the furthest extent of the CO_2 plume at the Model year 2089 (50 years post-injection), and blue is the position at model year 12, at the end of injection.

2.7 Change in Bottomhole Pressure

As shown in **Figure 2-25**, the bottomhole injection pressure at the Midland CCS #2 well rises gradually during injection as CO_2 diffuses through the system. The pressure reaches a maximum of 7,499 psi just before the end of injection in modeled year 2039.

Reference depths corresponding to the bottomhole pressure values in **Figure 2-25** are provided in **Table 2-15**. The maximum change in modeled bottomhole pressure (ΔBHP) at the end of injection (model year 12) is 1,598 psi at Midland CCS #2. This peak pressure occurs at the well and decreases exponentially with distance from the wellbore (**Table 2-16**).

The bottomhole pressure shown in **Figure 2-25** differs from grid block pressure, which represents the average pressure within the reservoir cell. These pressures are linked by the well index, a simulator-internal calculation that represents the ratio of well flow rate to the pressure difference between the reservoir block and the wellbore. A comparison of grid block and wellbore pressures at the top of the Devonian Injection Interval is also shown in **Figure 2-25**, where the observed difference is attributed to the well index.

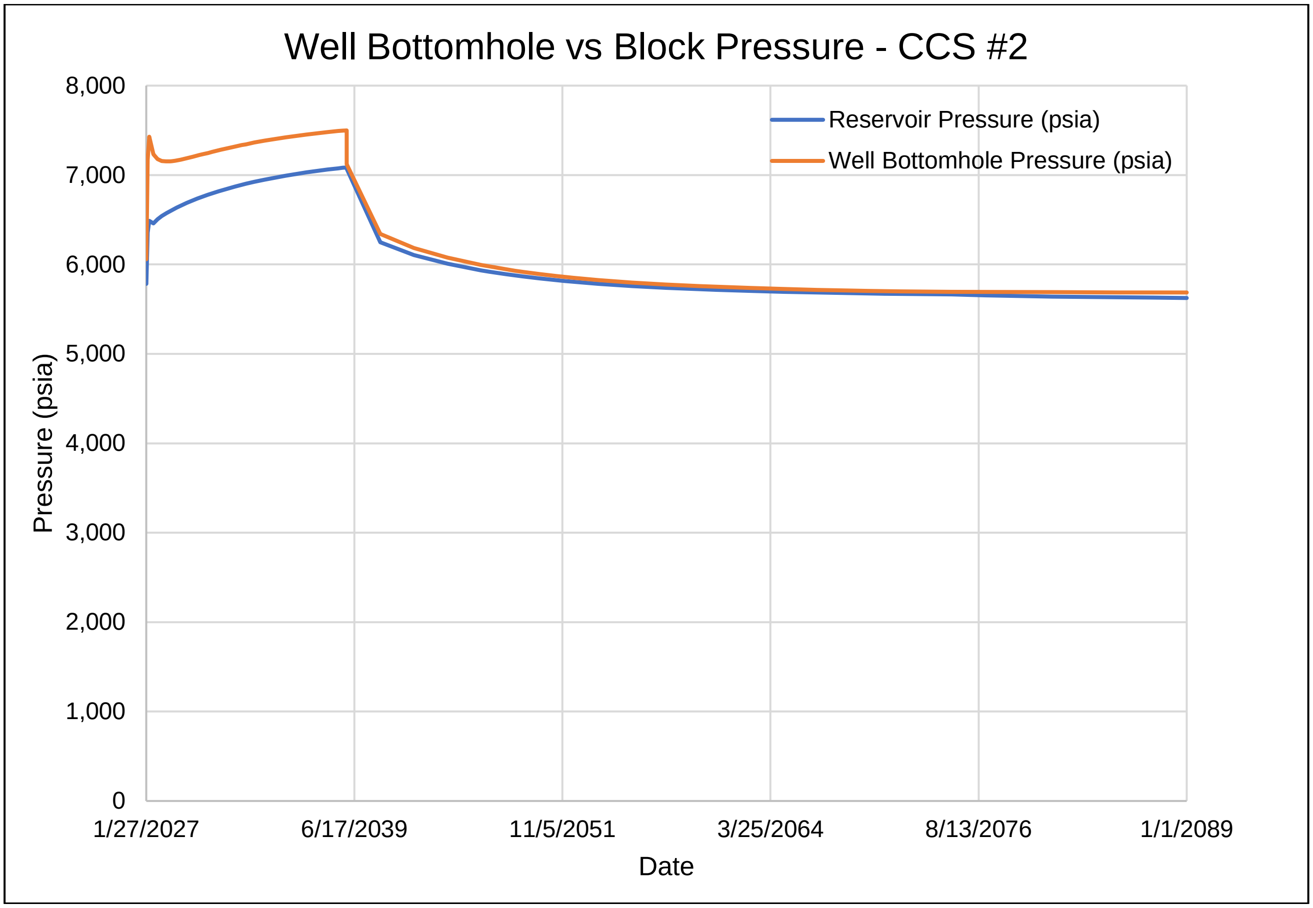

Figure 2-25: Well Bottomhole vs. Block Pressure Comparison
Values shown are from the Midland CCS #2 at the top of the Devonian interval.

Table 2-15: Reference Depths for Modeled Bottomhole Pressures in the Midland CCS #2

Well		Reference Depth (ft TVDSS)		Reference Depth Formation		Reference Depth Model Domain (k-layer)
Midland CCS #2		-9,403		Top of Devonian		28

To model the tubing head injection pressures, tubing tables were developed incorporating the proposed downhole tools and well configuration. The wellbore hydraulics model used to generate these tables includes the proposed injection stream (**Table 2-10**) and applies an equation of state (EoS) approach to calculate phase behavior, density, viscosity, and other relevant properties within the injection tubing. The modeled average tubing head injection pressure is 2,949 psi (see additional notes in ***Section 3****.)*

Following the end of injection in model year 2039, pressure within the reservoir begins to decline and gradually return to initial conditions. The maximum pressure change occurs immediately after injection ceases. The corresponding hypothetical incremental leakage rate, as defined in **Section 2.10 and Appendix L**, is 8.63E-06 bbl/day or 0.0031 bbl/yr, calculated at the Midland CCS #2 well—this is the highest leakage rate observed during the simulation. As pressure diffuses over the subsequent 50 years, the hypothetical leakage rates within the AoR decrease.

The principal source of uncertainty identified during the modeling and simulation process is the lack of direct measurements for key parameters, such as fracture width, fracture density, and other site-specific characteristics. These uncertainties will be addressed through the development of a stratigraphic test well and the associated evaluation of log and core data collected there and at future monitoring wells.

2.7.1 Operational Information

In this section, several tables and figures related to operational parameters and dynamic simulation results of the Well are presented.

- **Figure 2-26** shows the forecasted injection pressure at surface and bottomhole conditions at the top of the Devonian interval.
- **Figure 2-27** shows the gas injection schedule and cumulative gas injection over time.
- **Figure 2-28** presents the inventory of CO_2 by phase throughout the modeled timeframe, including trapped, supercritical, and dissolved CO_2.
- **Table 2-16** summarizes annual gas injection, cumulative gas injection, bottomhole pressure, and wellhead pressure for the site.
- Finally, **Table 2-17** provides the perforated intervals, injection schedule, and coordinates of the Well.

Additional details regarding plume diameter and CO_2 saturation can be found in **Section 2.6**.

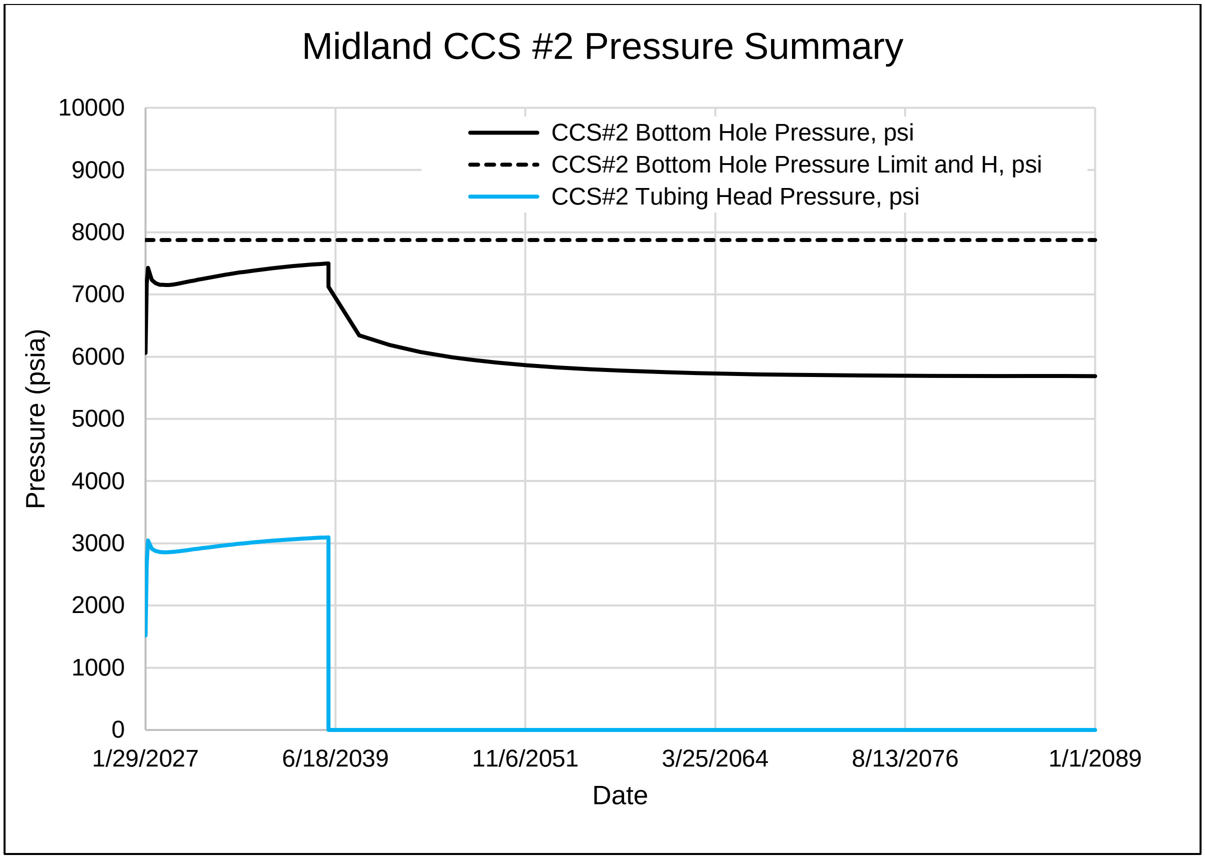

Figure 2-26: Midland CCS #2 Modeled Well Injection Pressures

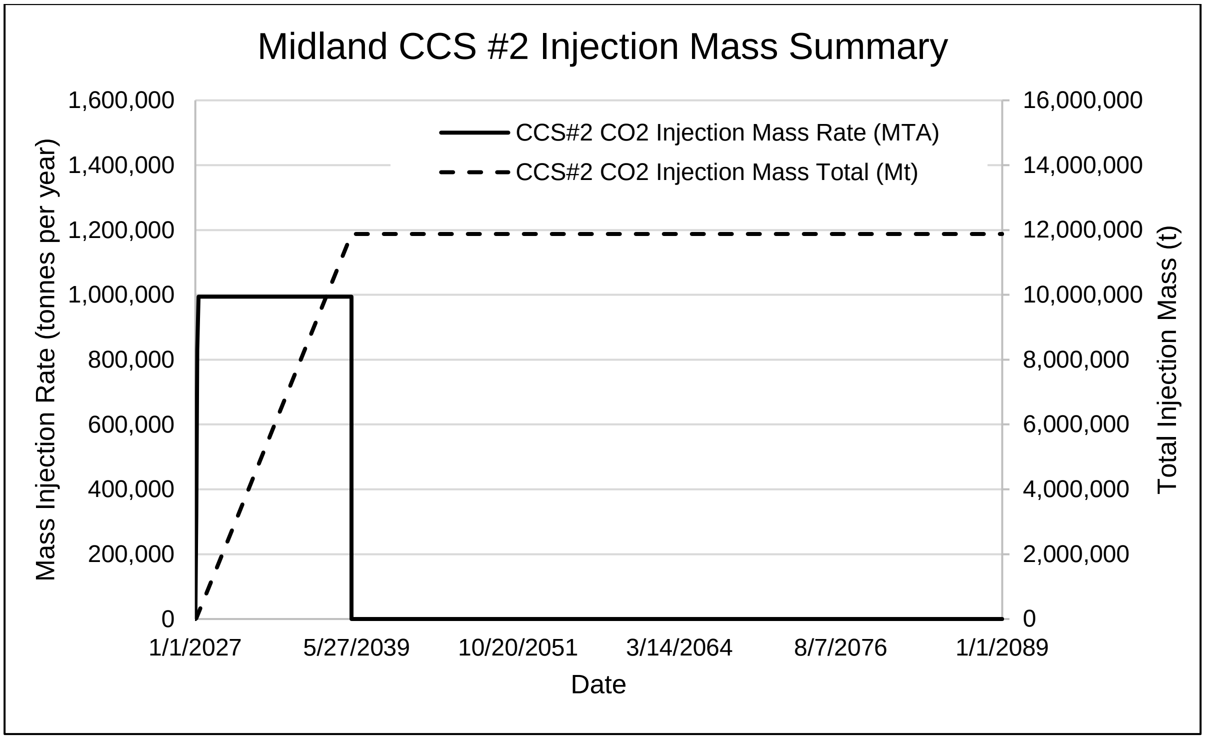

Figure 2-27: Midland CCS #2 Forecasted Injection Mass Rate and Cumulative Injection Mass

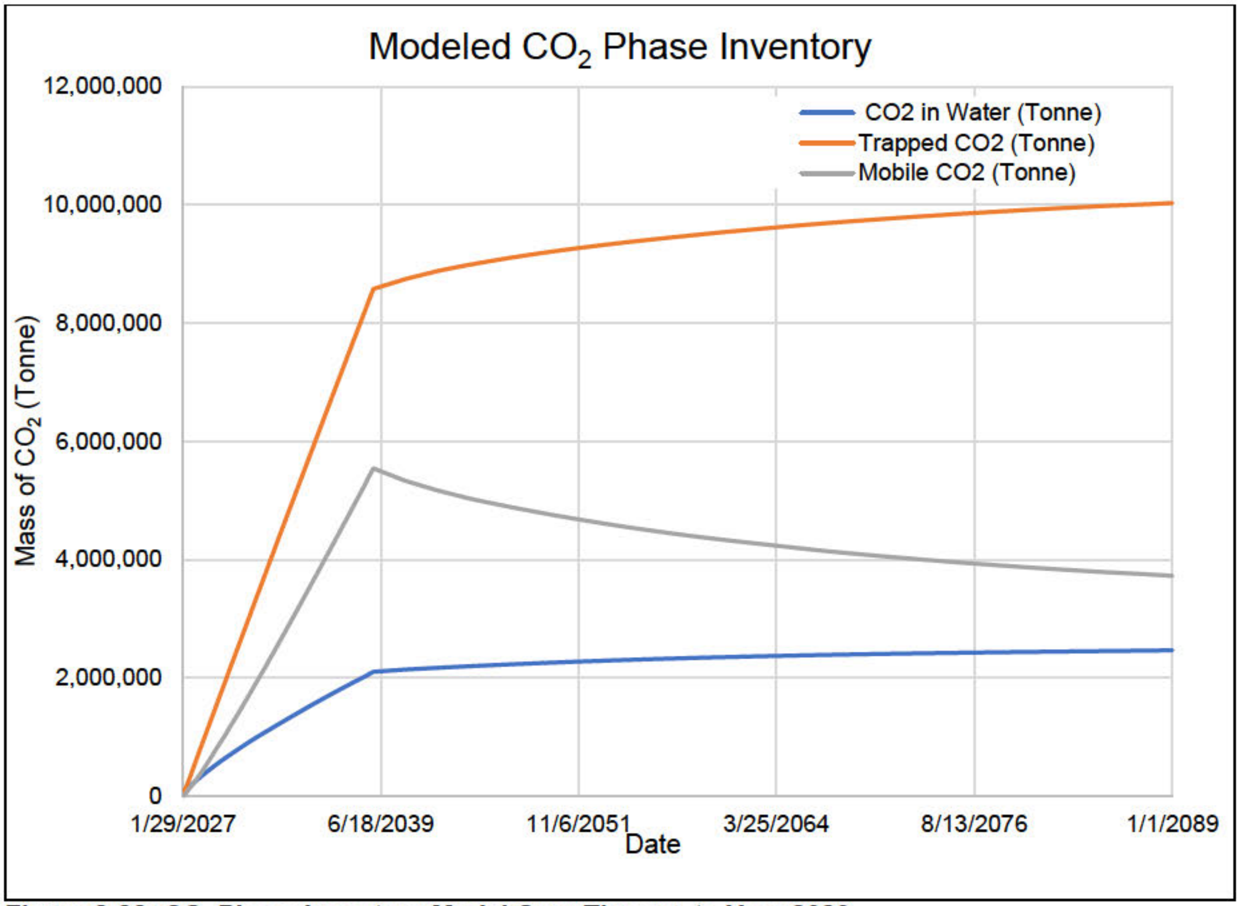

Figure 2-28: CO_2 Phase Inventory Model Over Time up to Year 2089

Table 2-16: Tabular Forecast Details for Midland CCS #2

Year		CO_2 Injection Rate (MMta)		Cumulative Gas Injected (MMt)		Well Head Pressure (psi)		Bottom Hole Pressure (psi)
2027		1.0[5]		1		1,519		6,059
2028		1.0		2		2,858		7,157
2029		1.0		3		2,865		7,167
2030		1.0		4		2,896		7,212
2031		1.0		5		2,929		7,259
2032		1.0		6		2,960		7,304
2033		1.0		7		2,988		7,344
2034		1.0		8		3,012		7,380
2035		1.0		9		3,034		7,411
2036		1.0		10		3,053		7,438
2037		1.0		11		3,070		7,462
2038		1.0		12		0		7,483
2039		SHUT-IN		12		0		7,499
2039		0		12		0		7,122

[5] Injection rate will be 1.0 MMta after initial buildup to that rate. There will be a conditioning period.

Year	CO_2 Injection Rate (MMta)	Cumulative Gas Injected (MMt)	Well Head Pressure (psi)	Bottom Hole Pressure (psi)
2041	0	12	0	6,342
2043	0	12	0	6,186
2045	0	12	0	6,076
2047	0	12	0	5,994
2049	0	12	0	5,930
2051	0	12	0	5,881
2053	0	12	0	5,841
2055	0	12	0	5,810
2057	0	12	0	5,785
2059	0	12	0	5,766
2061	0	12	0	5,749
2063	0	12	0	5,736
2065	0	12	0	5,725
2067	0	12	0	5,716
2069	0	12	0	5,709
2071	0	12	0	5,703
2073	0	12	0	5,698
2075	0	12	0	5,695
2077	0	12	0	5,693
2079	0	12	0	5,691
2081	0	12	0	5,690
2083	0	12	0	5,689
2085	0	12	0	5,688
2087	0	12	0	5,687
2089	0	12	0	5,687

Table 2-17: Operating Details

Operating Information	Midland CCS #2
Location (global coordinates) X Y	 2,541,496.16 11,461,870.27
Model Coordinates (ft) X Y	 2,541,496.16 11,461,870.27
No. of perforated intervals	3
Perforated interval 01/01/2027 (ft, TVDSS) Z top Z bottom	 8,367 11,996
Wellbore diameter (ft)	0.5104
Planned injection period Start End	 01/01/2027 01/01/2039
Injection duration (years)	12
Injection rate (scf/day)*	54,516,445

TVDSS: True Vertical Depth Subsea

2.7.2 Fracture Pressure and Upper Limits for Injection

Calculated fracture gradients and maximum injection pressures are provided in **Table 2-18**. Derived from log analysis (**Section 1**), a fracture gradient of 0.72 psi/ft was calculated for the Ellenburger, and 0.74 psi/ft for the Devonian. These gradients correspond to pressure ranges of 9,500–10,500 psi in the Ellenburger and 8,500–9,500 psi in the Devonian. (see **Table 2-8** and **Table 2-9**)

The maximum bottomhole injection pressure used in the dynamic simulation was set at 90% of the calculated fracture gradient for both formations. The simulated maximum bottomhole pressure, recorded at the top of the Devonian interval at -9,403 ft TVDSS in the Midland CCS #2 well, was 7,499 psi.

At no point during the simulation did the modeled reservoir pressure exceed 90% of the fracture gradient in either the Ellenburger or the Devonian. **Figure 2-26** displays the calculated bottomhole pressure over time in relation to this 90% threshold at the top of the Devonian interval; reference depths are provided in **Table 2-15**.

Table 2-18: Injection Pressure Details

Injection Pressure Details	Unit	Midland CCS #2 Well
Minimum Fracture gradient Devonian	psi	0.72
Maximum injection pressure Devonian (90% of fracture pressure)	psi	0.65
Elevation (TVDSS) corresponding to maximum injection pressure Devonian	ft	-9,403
Elevation (TVDSS) at the top of the perforated interval Devonian	ft	-9,403
Elevation (TVDSS) at the bottom of the perforated interval Ellenburger	ft	-11,052
Calculated maximum allowable injection pressure (90% of frac pressure) at the top of the perforated interval Devonian	psi	7,875
Observed maximum bottom hole pressure from dynamic simulation model	psi	7,499

TVDSS: True Vertical Depth Subsea

2.7.3 Model Calibration and Validation

Milestone used extensive publicly available data compiled from the Railroad Commission of Texas (RRC) to calibrate its dynamic model by history matching the performance of adjacent saltwater disposal (SWD) wells, as listed in **Table 2-19**. In addition to these wells, three additional SWD wells were incorporated into the Model to further refine the impact of offset brine injection on initial reservoir pressure, both prior to and during CO_2 injection.

The six SWD wells listed in **Table 2-19** were incorporated into the dynamic simulation using reported historical injection volumes and estimated remaining injection capacity. Each well was projected to have an approximate 20-year lifespan, with a constant injection rate equal to the average of the last 12 months of reported data (see **Table 2-20**). The location of the SWD wells within the dynamic model domain is shown in **Figure 2-1** and **Figure 2-29**. Three of the wells were history matched to validate the model.

Table 2-19: List of Offset Injection Wells Used in the Dynamic Simulation Model

Well Name	API	Use	Completed Formation
Senor Salado SWD 17SD	42-329-42946-00	History Match	Ellenburger
Davidson Unit 1 0106BH	42-461-40597-01	History Match	Ellenburger
Clay Henry SWD 1	42-329-42349-00	History Match	Ellenburger
Coupes SWD 1	42-329-43582-00	SWD	Ellenburger
Midkiff SWD 1	42-329-42597-00	SWD	Devonian-Silurian + Ellenburger
Greg Midkiff SWD 1501	42-329-42371-00	SWD	Ellenburger

Table 2-20: Offset Injection Well Data

Well Name	Injection Start Date	Injection Stop Date	Assumed Future Injection Rate (bbl/day)
Senor Salado SWD 17SD	8/1/2019	1/1/2039	13,330
Davidson Unit 1 0106BH	7/1/2018	1/1/2037	5,074
Clay Henry SWD 1	2/1/2019	1/1/2039	12,536
Coupes SWD 1	2/1/2021	6/1/2022	0
Midkiff SWD 1	2/1/2019	1/1/2039	3,678
Greg Midkiff SWD 1501	4/1/2019	1/1/2039	2,786

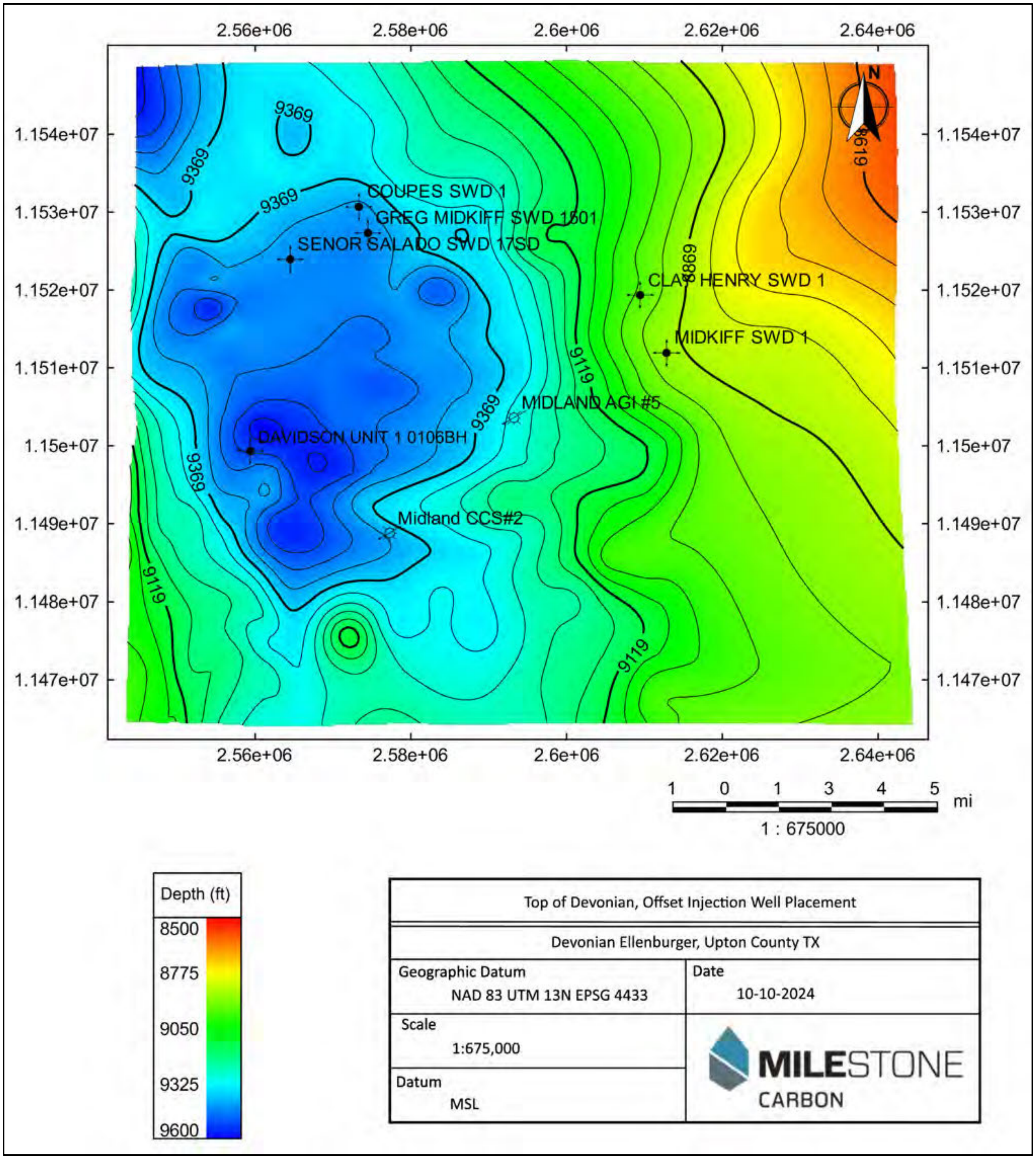

Figure 2-29: Location of Offset Injection Wells, Structure Map Top (TVDSS) of Devonian

The primary objective of history-matching the offset injection wells was to calibrate the static model's intrinsic permeability and fault transmissibility. Historical injection volumes and completion details from the RRC were loaded into the dynamic simulation model. Various combinations of permeability and fault transmissibility were iterated to achieve the best fit with the reported tubing head pressures. The calibrated model's resulting tubing head pressures are shown in **Figure 2-30**.

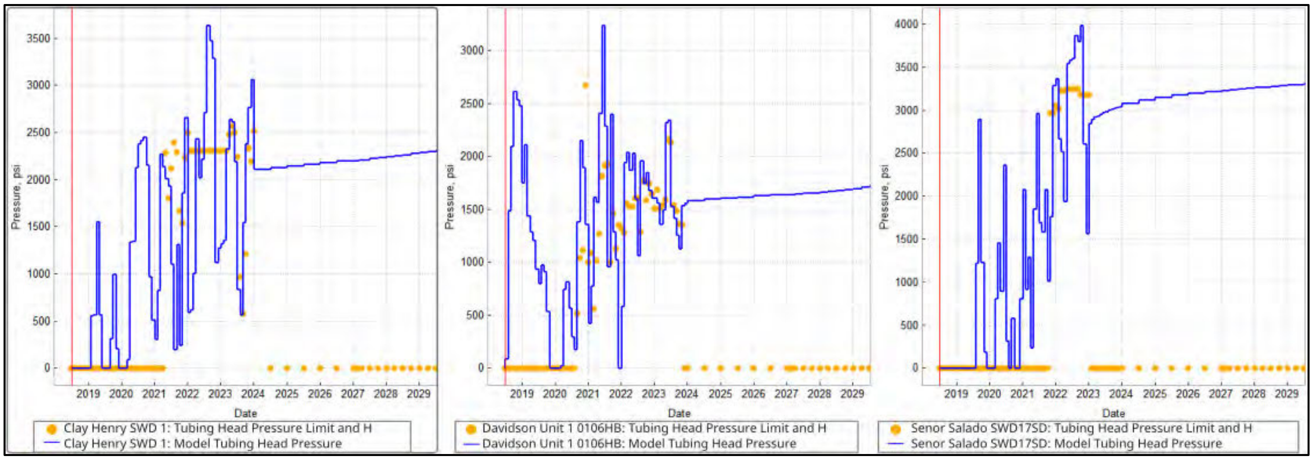

Figure 2-30: Tubing Head Pressures
Historical tubing head pressures (orange dots) compared to simulated tubing head pressures (blue lines).

The Model domain was subdivided into four regions as shown in **Figure 2-31**. The aerial segmentation honors the geobodies described by Holtz and Kerans (1992) and Sanchez et al. (2019). The geobody located in the eastern half of the dynamic simulation model domain (Regions 3 and 4) represents areas with increased fracturing or karsting. Vertically, strata above the Ellenburger Group were assigned to Regions 1 and 4, while the Ellenburger itself was assigned to Regions 2 and 3.

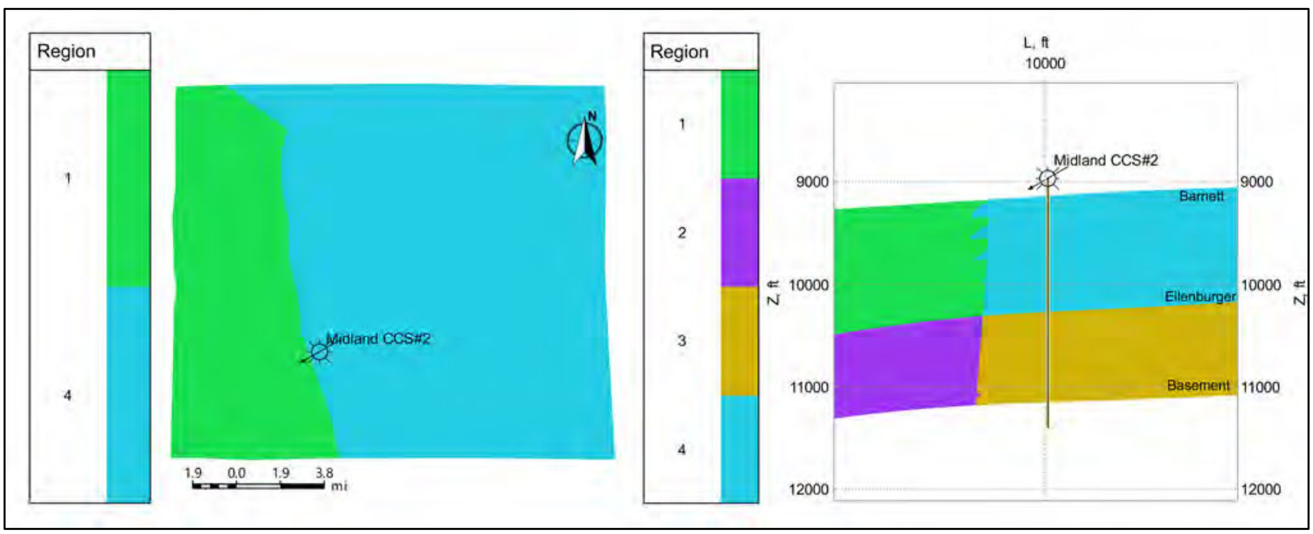

Figure 2-31: Model Regions Used in History Matching

Utilizing the historical injection volumes from the Midkiff SWD 1 well (API: 42-329-42597), an initial effort was made to calibrate the permeability of the interval above the Ellenburger independently from the Ellenburger itself. Midkiff SWD 1 is the only known historical dual-zone completion—including both the Devonian–Silurian and Ellenburger formations—within the Model domain. However, it was ultimately determined that insufficient data are available from Midkiff SWD 1 to support this additional segmentation. A summary of the resulting permeability multipliers used in the Model is provided in **Table 2-21**.

Table 2-21: Summary of Permeability Multipliers

Model Region	Permeability Multiplier
Region 1	0.250
Region 2	0.250
Region 3	0.475
Region 4	0.475

Well performance in Regions 1 and 2 was best approximated using a 75% reduction in the static model's permeability. In Regions 3 and 4, performance was best matched with a 52.5% reduction. The variability in effective permeability is likely attributed to natural fracturing or localized karsting.

The impact of low fault transmissibility was evident in the elevated tubing head injection pressures observed at the Davidson Unit 1 0106BH SWD well (API: 42-461-40597) and the Senior Salado SWD 17SD well (API: 42-329-42946). No additional data were available at the time of this permit to further quantify fault transmissibility or to differentiate transmissibility values between individual faults within the Model domain. The performance of both wells was best approximated with a fault transmissibility value of 0.01, which was applied uniformly to all faults in the Model pending the availability of further data.

2.8 Corrective Action Introduction

Milestone utilized the results of the numerical modeling and critical pressure analysis to conservatively delineate the Area of Review (AoR) for the Midland CCS facility. Given the negative calculated critical pressure threshold, and the presence of offset saltwater disposal activity contributing to regional overpressure, reliance on analytical methods alone was not considered sufficiently protective. Instead, the AoR was defined using a dual-criteria approach based on (1) the lateral extent of the modeled pressure front exceeding the threshold for potential leakage through a hypothetical borehole, and (2) the extent of supercritical CO_2 saturation exceeding 2% at plume stabilization. This methodology is consistent with EPA Class VI guidance and follows conservative practices employed in similar approved permits.

Following delineation of the AoR, Milestone reviewed all artificial penetrations—wells and stratigraphic borings— within the AoR to assess the need for corrective action. Based on this review, zero (0) wells were identified as requiring corrective action. A full table of all wells within the AoR can be found in **Section 1.14.2** of the permit.

As specified in **Section 2.12**, and at least once every 5 years, or when monitoring and operational conditions warrant, Milestone will:

1) Reevaluate the AoR consistent with previous modeling methodology.
2) Identify all wells in the re-evaluated AoR that may require corrective action.
3) Perform corrective action on wells requiring corrective action in the reevaluated Area of Review.
4) Submit an amended Area of Review and Corrective Action Plan or demonstrate to the Director—based on monitoring data and modeling results—that no amendment is necessary.

Any amendments to the Area of Review and Corrective Action Plan must be approved by the Director, incorporated into the permit, and are subject to the permit modification requirements at 40 CFR § 144.39 or § 144.41, as applicable.

2.9 Critical Pressure Calculations

The critical pressure threshold defines the minimum increase in pressure within the injection interval that would be sufficient to drive formation fluids through a hypothetical conduit into the lowermost USDW. This concept is central to EPA's Class VI Area of Review (AoR) delineation methodology, as described in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* (USEPA, 2013). For this project, the threshold was calculated using a modified version of the Thornhill et al. (1982) approach (**Equation 9**), which estimates the pressure required to equalize hydraulic head between two stratigraphic intervals, updated here with site-specific pressure gradients. The critical pressure at the interface between the injection interval and a hypothetical conduit to the USDW is calculated as:

Equation 9: Thornhill 1982 Pressure

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i)$$

Where:

$P_c = Critical\ Pressure\ Threshold\ (Pa)$
$P_u = Initial\ Fluid\ Pressure\ in\ the\ USDW\ (Pa)$
$\rho_i = Injection\ Interval\ Fluid\ Density\ (kg/m^3)$
$g = Acceleration\ Due\ to\ Gravity\ \ (9.81\ m/s^2)$
$z_u = Elevation\ of\ the\ Lowermost\ USDW\ (m)$
$z_i = Elevation\ of\ the\ Injection\ Interval\ (m)$

The pressure increase that the injection interval can accommodate before exceeding the critical threshold is:

Equation 10: Critical Pressure

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i) - P_i$$

Where:

$\boldsymbol{P_i = Initial\ Reservoir\ Pressure\ in\ the\ Injection\ Interval\ (Pa)}$

In the Midland CCS #2 well, the base of the USDW is expected to occur at 1,250 ft TVD, based on a Groundwater Advisory Unit (GAU) determination (**Section 1.4**). The critical pressure calculation was performed for the top of the Devonian injection interval, located at 12,200 ft TVD. The fluid in the injection interval is assumed to be formation brine with a salinity of 152,704 mg/L, corresponding to a fluid density of 1,052 kg/m^3 (as shown in **Table 2-22**). This value is derived using 207 water samples from nearby Devonian and Ellenburger wells and using McCain's temperature correction to correct the density to reservoir conditions. (McCain, 1999)

The initial reservoir pressure, immediately prior to the start of injection, was calculated using a pressure gradient of 0.45699 psi/ft, resulting in an expected pressure of approximately 5,575 psia. As shown below, the initial pressure gradient used in the simulation is 0.45 psi/ft (initialized in 2018); however, this gradient has been increased by offset SWD activity prior to the commencement of CO_2 injection and is not consistent with the fluid density of the injection interval. Therefore, a more precise value of 0.45699 psi/ft is utilized to calculate the critical pressure.

In contrast, the fluid within the lowermost USDW is assumed to have a pressure gradient of 0.4370 psi/ft and a salinity of 11,030 mg/L, consistent with Dockum Group brines (see **Section 1.4.2** for salinity assumptions). A summary of the inputs used in the critical pressure threshold calculation is provided in **Table 2-22**.

Far-offset Class II SWD injection wells appear to have increased the pore pressure gradient prior to any injection activities associated with this Class VI permit. SWD wells included in the numerical model have increased the pressure gradient. Milestone used the value of the reservoir pressure consistent with the density, immediately prior to the start of injection are used to calculate the critical pressure.

Table 2-22: Inputs for Critical Pressure Calculation at conditions directly before Injection[6]

Input	Variable	Value	SI Value
Depth (TVD) to Base of USDW	z_u	- 1,250 ft	- 381.0 m
Depth (TVD) to Top of Injection Unit (Devonian)	z_i	- 12,200 ft	- 3,718.56 m
Fluid Density in Injection Unit (Devonian)	ρ_i	8.78087 ppg	1,052.18 kg/m^3
Initial Pressure at Base of USDW	P_u	546.25 psia	3,766,261.16 Pa
Initial Pressure at Top of Injection Unit	P_i	5,575.24 psia	38,439,948.98 Pa

The initial conditions used in the pressure threshold analysis are based on a comprehensive review of published literature, analog well data, offset water data, and regional geologic studies. While no site-specific data has been collected to date, a stratigraphic test well is planned to confirm reservoir properties and validate model assumptions. Formation temperature at the top of the Devonian injection interval is estimated to be 188.4°F, sufficient to maintain supercritical CO_2 conditions under the modeled pressure regime. Porosity and permeability values used in the model—1.98% and 0.8 to 3.7 mD, respectively—were derived from regional analogs and log-based estimates from nearby Devonian-age reservoirs. These values are described in **Section 2.4.9.2** of the Site Characterization Report and reflect conservative inputs pending site-specific validation.

To evaluate the critical pressure threshold between the injection interval and the USDW, values from **Table 2-22** were substituted into **Equation 10**, provided below. (it is important to maintain rounding)

$$\Delta P_c = P_u + \rho_i g * (z_u - z_i) - P_i$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 1{,}052.18\ kg/m^3 * 9.80665\ m/s^2 * (-381.0m - (-3{,}718.56\ m)) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 1{,}052.18\ kg/m^3 * 9.80665\ m/s^2 * (3{,}337.56\ m) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 10{,}318.36\ Pa/m * (3{,}337.56\ m) - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 3{,}766{,}261.16\ Pa + 34{,}438{,}145.60\ Pa - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = 38{,}204{,}406.76\ Pa - 38{,}439{,}948.98\ Pa$$

$$\Delta P_c = -235{,}542.22\ Pa$$

$$\Delta P_c = \frac{-235{,}542.22\ Pa}{6{,}894.76} = -34.1625\ psia\ \pm 1$$

The resulting critical pressure prior to injection from **Equation 10** is a negative value of **-34.1625 psia**. Because the calculated pressure threshold is negative and the injection interval is known to be over pressured under baseline conditions, a more conservative approach was adopted to ensure robust protection of Underground Sources of Drinking Water (USDWs). The calculated critical pressure was likely positive before being altered by historic and ongoing saltwater disposal activities. Additionally, it is highly likely that as the project moves forward additional SWD wells will be drilled into the Ellenburger, and even though they are far from the Midland CCS #2 well, they will still influence the pressure of the formation.

To assess this risk, a conservative numerical modeling approach was applied to evaluate whether pressure increases could result in vertical fluid migration into a USDW. This threshold analysis supports the need to define the Area of Review using a methodology that accounts for both pressure-driven transport potential and the spatial distribution of injected CO_2. The outcome of this analysis informed the approach to AoR delineation.

[6] 1 psia = 6894.75728 Pa; 1 foot = 0.3048 meters; 1 kg/m3 = 0.00834540445 ppg

2.10 Area of Review Delineation

Given the negative calculated critical pressure, reliance on Method 1 alone is not sufficient to support the delineation of the Area of Review (AoR) for this project. As recommended in the EPA Class VI AoR guidance (USEPA, 2013), for over-pressured or negative critical pressure conditions, a more conservative and site-specific modeling approach was adopted to ensure robust protection of Underground Sources of Drinking Water (USDWs).

This approach incorporates EPA's Methods 2 and 3, which are designed to evaluate leakage through hypothetical boreholes and simulate solute transport within overlying aquifers. The modeling framework follows a methodology similar to those used in other approved Class VI projects in the region, where conservative bounding-case scenarios were applied to evaluate the impact of pressure propagation and potential fluid migration. In this case, four representative borehole scenarios were evaluated: the injection well (CCS #2), which is anticipated to see the highest reservoir pressure, and three conservatively placed hypothetical open boreholes located radially along the CO_2 plume edge.

To address these concerns, a site-specific, multiphase flow and solute transport model was developed using the MODFLOW-SEAWAT (Version 4) platform, developed by the U.S. Geological Survey. This platform supports variable-density flow, salinity and temperature effects on viscosity and density, and multiphase pressure transport. The model incorporated detailed site-specific stratigraphy and petrophysical properties, including porosity and permeability values from core data and literature. **Table 2-23** summarizes the modeled formations and associated hydrogeological parameters.

Table 2-23 Stratigraphic column and hydrogeologic properties for modeled formations

Formation	Type	Measured Depth	Thickness	Permeability (mD)	Porosity	TDS (mg/L)
Trinity	USDW	0	280	3000	10.0%	1242
Dockum	USDW	280	970	93	10.0%	11030
Dewey Lake and Rustler	Confining	1250	1234	0.005	10.0%	n/a
Tansill-Grayburg	Dissipation	2484	1636	11	13.3%	n/a
San Andres	Dissipation	4120	1160	9.49	10.3%	n/a
Glorieta	Confining	5280	2291	0.090169	1.6%	n/a
Spraberry	Confining	7571	1361	0.001032	4.6%	n/a
Dean	Confining	8932	192	0.000578	4.3%	116466
Wolfcamp	Dissipation	9124	1004	0.000591	4.3%	n/a
Cisco	Confining	10128	367	0.000819	5.0%	n/a
Canyon	Confining	10494	350	0.000607	4.3%	n/a
Strawn	Dissipation	10845	658	2	4.7%	n/a
Atoka	Confining	11503	430	0.001152	6.1%	n/a
Barnett shale	Confining	11933	134	0.000001	5.8%	n/a
Woodford shale	Confining	12066	104	0.00015	5.4%	n/a
Devonian	Reservoir	12170	532	5.895	2.6%	152704
Silurian	Confining	12703	41	2.77	1.0%	n/a
Fusselman	Confining	12744	192	2.2203	1.2%	n/a
Simpson	Confining	12936	130	0.62	1.5%	n/a
Ellenburger	Reservoir	13066	883	6.441	3.5%	152704

The conceptual model represents a fully open 8-inch borehole extending from the Devonian Injection Unit to the water table, without any cement isolation. A highly conservative permeability value of 1×10^{-10} m² (approximately 101,325 mD) was assigned to the borehole to simulate a worst-case leakage condition. This value exceeds those associated with even the highest-leakage abandoned well categories reported in the literature (Celia et al., 2011) and reflects a bounding-case assumption consistent with EPA Method 2. The borehole configuration and permeability assignment are shown in **Figure 2-32**.

Table 2
Mapping of well score to mean effective well permeability. Data in columns marked with * from Watson and Bachu (2008).

Deep leakage potential*	Score range*	Well effective permeability mean [mD]
Low	<2	0.01–0.02
Medium	2–6	0.02–0.5
High	6–10	0.5–8
Extreme	>10	8–10,000

M.A. Celia et al. / International Journal of Greenhouse Gas Control 5 (2011) 257–269

Figure 2-32: Conceptual representation of borehole permeability used in the AoR model.

In each simulation scenario, the injection interval was designated as the source zone for upward pressure propagation through the hypothetical borehole. To standardize the model and prevent inconsistencies related to formation thickness, the uppermost 33 feet (10 meters) of the injection unit was assumed to be hydraulically connected to the USDW, irrespective of the actual thickness of the Ellenburger or Devonian formations at a given location.

Simulations were conducted using a 600 psia pressure increase in the San Andres Formation over a 70-year injection period. This pressure was derived from present-day aggregate offset shallow injection pressure data reported to TRRC through Texnet reporting system, Milestone's operated wells nearby, and B3 data. An additional case with no pressure increases in the San Andres was tested, to be conservative, even though increases are probable and have been verified by well data.

The pressure associated with injection is assumed to propagate vertically through a sequence of confining and dissipation layers (including Dewey Lake, Rustler, and Dockum formations). The model applied general head boundary conditions at 1,000 meters from the model edge and a west-to-east regional hydraulic gradient to reflect ambient groundwater flow (**Figure 2-33**).

Table 2-24: Results of Modflow Simulation of Hypothetical Leakage at Various Locations

Simulation	Injection Unit	Maximum Incremental Concentration Increase of TDS (mg/L)							
		CCS #2 Well		JRS Farms Well		North Location #1		SW Location #2	
		Trinity	Dockum	Trinity	Dockum	Trinity	Dockum	Trinity	Dockum
Base Case	Devonian	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.01
	Ellenberger	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
No Dissipation Zones	Devonian	0.36	23.92	0.11	7.58	0.06	5.99	0.11	10.31
	Ellenberger	0.20	11.48	0.12	6.88	0.07	5.91	0.11	8.54

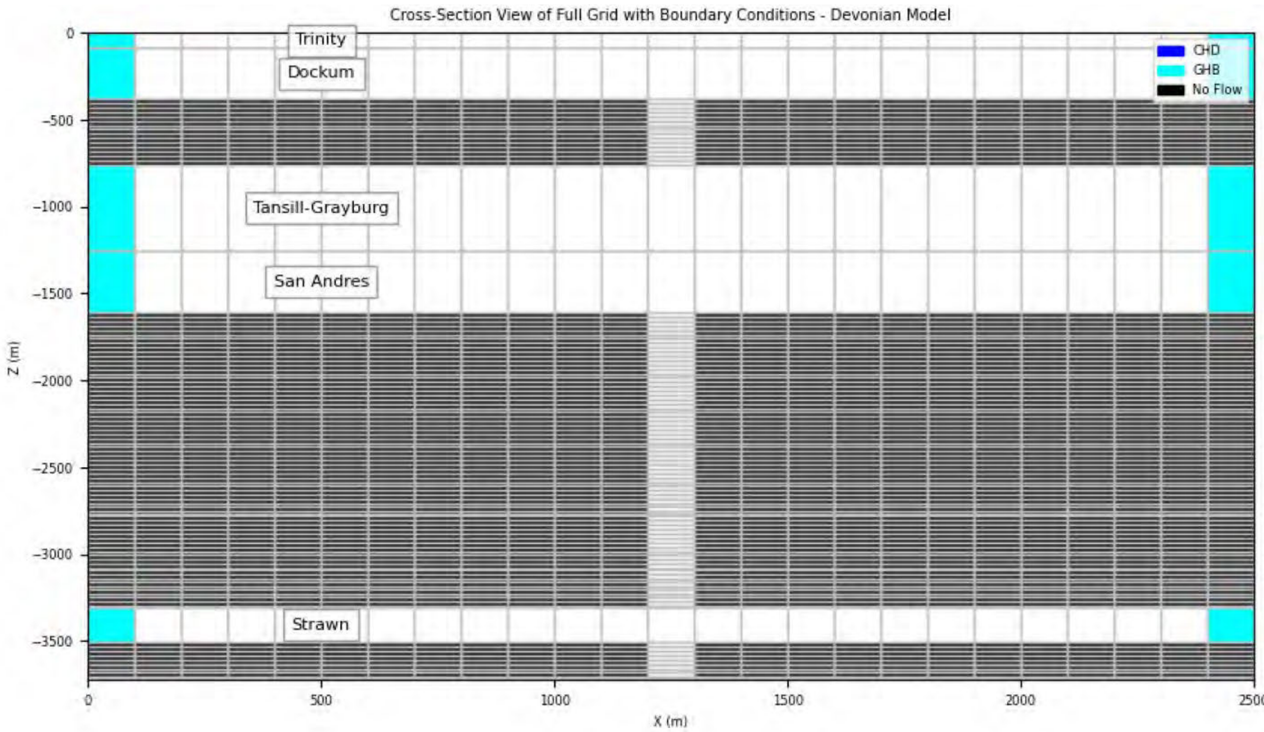

Figure 2-33: Numerical grid used in the Devonian borehole model (distances in meters)

Model outputs were used to evaluate potential fluid migration and changes in water quality in the overlying USDWs. Results from both baseline and elevated pressure simulations demonstrated no net increase in TDS above 1 mg/L in either the Trinity or Dockum USDWs after 70 years of injection in deeper intervals. Dissipation zones effectively attenuated both pressure and solute transport, and all observed TDS changes remained confined to subsurface intervals below the USDWs. (**Table 2-24**).

Model results also indicate that, under the worst-case scenario involving an abandoned borehole located within close proximity to the injection well and assuming no intervening dissipation zones, the maximum total dissolved solids (TDS) increase within the USDW is less than 24 mg/L. This impact is highly localized, confined to an area within approximately 100 meters of the well pad. Beyond this immediate vicinity, changes in TDS within the aquifer are negligible, remaining below 1 mg/L (**Figure 2-34**).

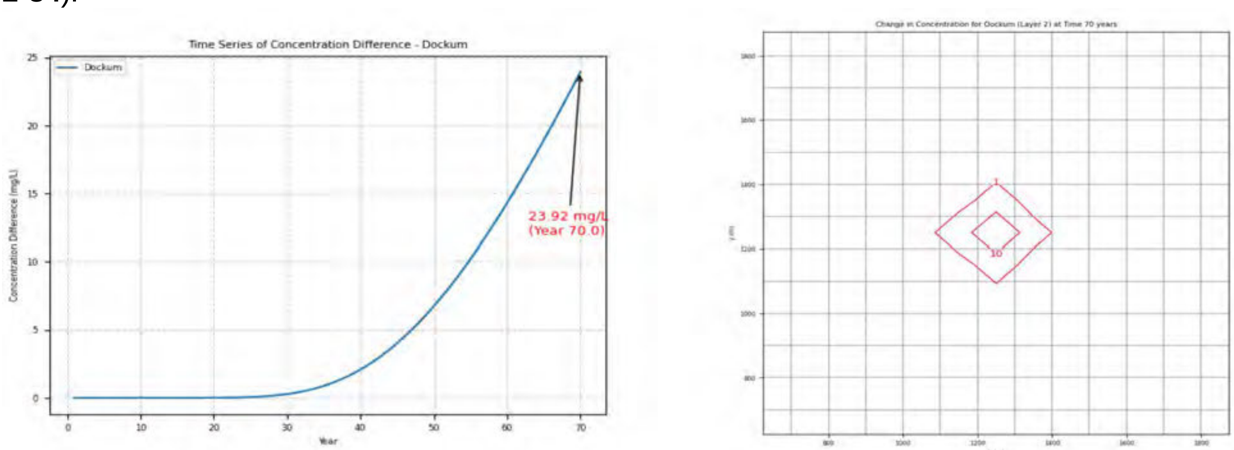

Figure 2-34: SEAWAT Results for Dockum, No Dissipation Zones, Worst Case Scenario, Highest ΔP

Accordingly, delineation of the AoR was based not solely on the analytical critical pressure threshold but rather on modeled pressure front extents and plume behavior. This dual-criteria approach provides a more technically robust and protective delineation strategy. Specifically, the AoR is defined by:

1. The modeled extent of the supercritical CO_2 plume, where saturation exceeds 2% at 50 years post-injection; and
2. The lateral extent of modeled pressure increase associated with the onset of potential leakage through a hypothetical high-permeability borehole(s).
    a) Since the lateral extent of the potential leakage is <100 M from the injection well, and <1M at locations along the edge of the CO_2 plume, the AoR is less than or equal to #1.

Figure 2-35 presents the modeled incremental pressure increase shown in equivalent mud weight between 2027 and end of 2039 at the top of the injection interval. **Figure 2-36** presents the modeled incremental pressure increase shown in equivalent mud weight between 2027 and 2039 at the top of the Ellenburger Injection Unit. **Figure 2-37** shows the pressure at the top of the Injection unit in PSI with the Class VI AOR only. These figures demonstrates that pressure changes remain laterally constrained and rapidly attenuate away from the injection point due to the site's low-permeability injection reservoir. Note that 0.45699 psi/ft, the regional pore pressure gradient (**Figure 2-17**), is equivalent to 8.78 ppg mud weight. Additional maps of pressure are included in the Modflow Appendix.

The results also indicate that pressure encroachment from nearby Class II Saltwater Disposal (SWD) and Acid Gas Injection (AGI) wells varies across different K-layers, complicating the delineation of a distinct pressure boundary associated with the Class VI injection well. Due to the lack of a clearly defined pressure boundary—attributable to cumulative effects from surrounding Class II injection activity—advanced leakage modeling was undertaken to better assess potential impacts. Additionally, the figures illustrate that future SWD wells, even those located at considerable distances from the Class VI well, could influence regional pressure conditions. As a result, reliance on Method 1 is not appropriate for this site. Milestone cannot ensure that the Texas Railroad Commission (TRRC) will restrict future deep injection activities outside the current CO_2 plume footprint.

This pressure front approach is consistent with methods used in previously approved Class VI permits, where the AoR was delineated using modeled sensitivity to pressure-induced leakage under conservative assumptions. In the Midland CCS case, four boreholes, including the injection well and three strategically placed hypotheticals, were simulated under bounding-case conditions using SEAWAT. Even with assumed borehole permeabilities exceeding those associated with high-risk legacy wells, no net increase in TDS was observed in either the Trinity or Dockum USDWs over the 70-year simulation period.

These findings confirm that the modeled CO_2 plume and associated pressure front provides a protective and site-specific basis for identifying at-risk artificial penetrations and informing corrective action planning.

Furthermore, the MODFLOW-SEAWAT model defines the zone of elevated pressure associated with CO_2 injection—representing the area of potential risk to USDWs—as being less than or equal to the spatial extent of the CO_2 plume, as delineated by a 2% saturation threshold. This outcome reflects the negligible leakage rates predicted for a hypothetical wellbore under conservatively modeled pressure conditions, which are insufficient to produce detectable impacts within the USDW.

This AoR delineation method provides a conservative, transparent, and technically defensible framework consistent with EPA Class VI expectations. Additional MODFLOW-SEAWATT model inputs, sensitivity cases, and configuration details are provided in **Appendix L**.

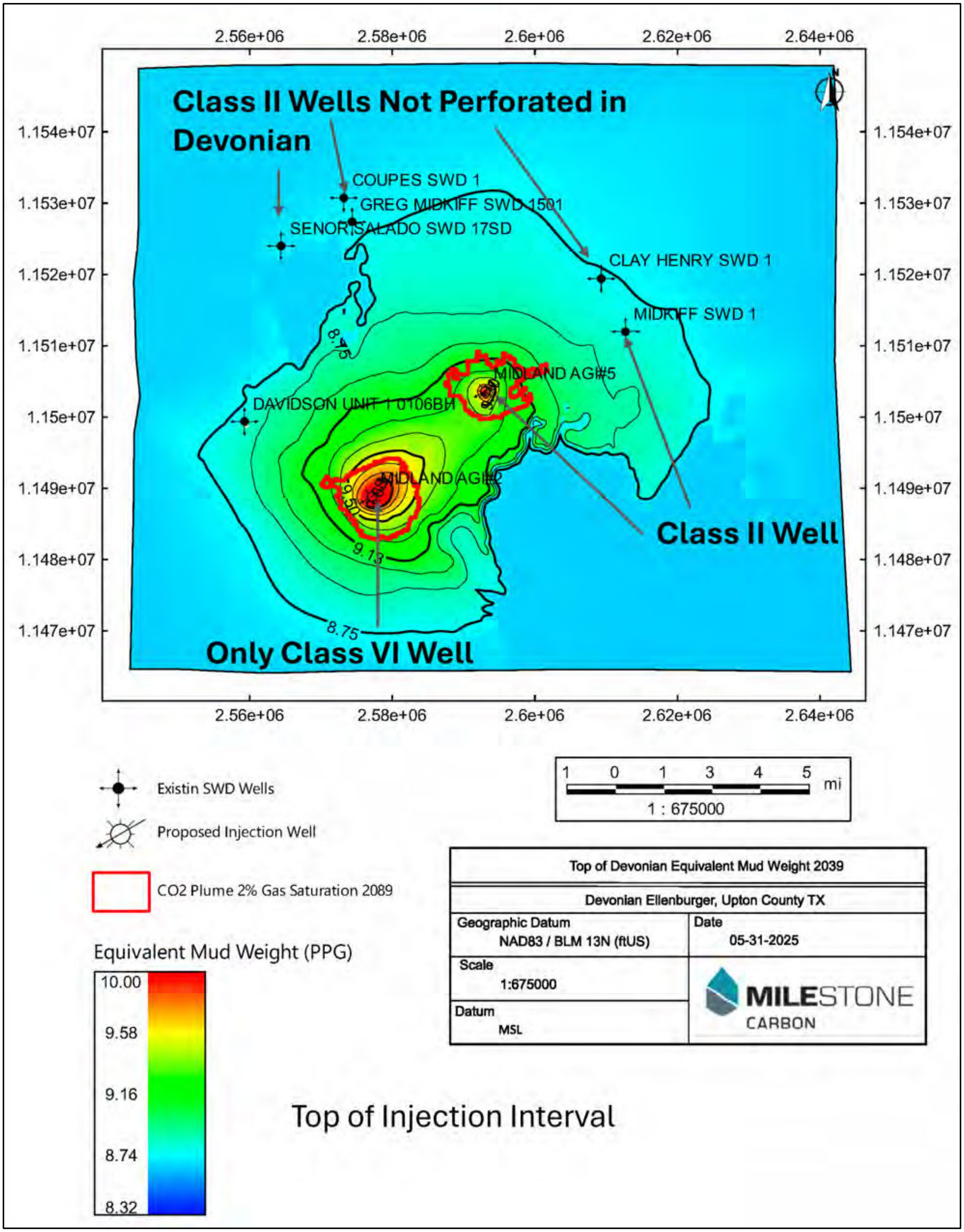

Figure 2-35: Maximum change in reservoir pressure at Top of Devonian formation

Maximum change in reservoir pressure across in 1st K-layer in the Injection Interval from model years 2027 (start of injection) to 2039 (end of injection). Contours shown in equivalent Mud Weight PPG. Not all wells perforated in Devonian. No faults shown because faults do not intersect top K-layer of Devonian.

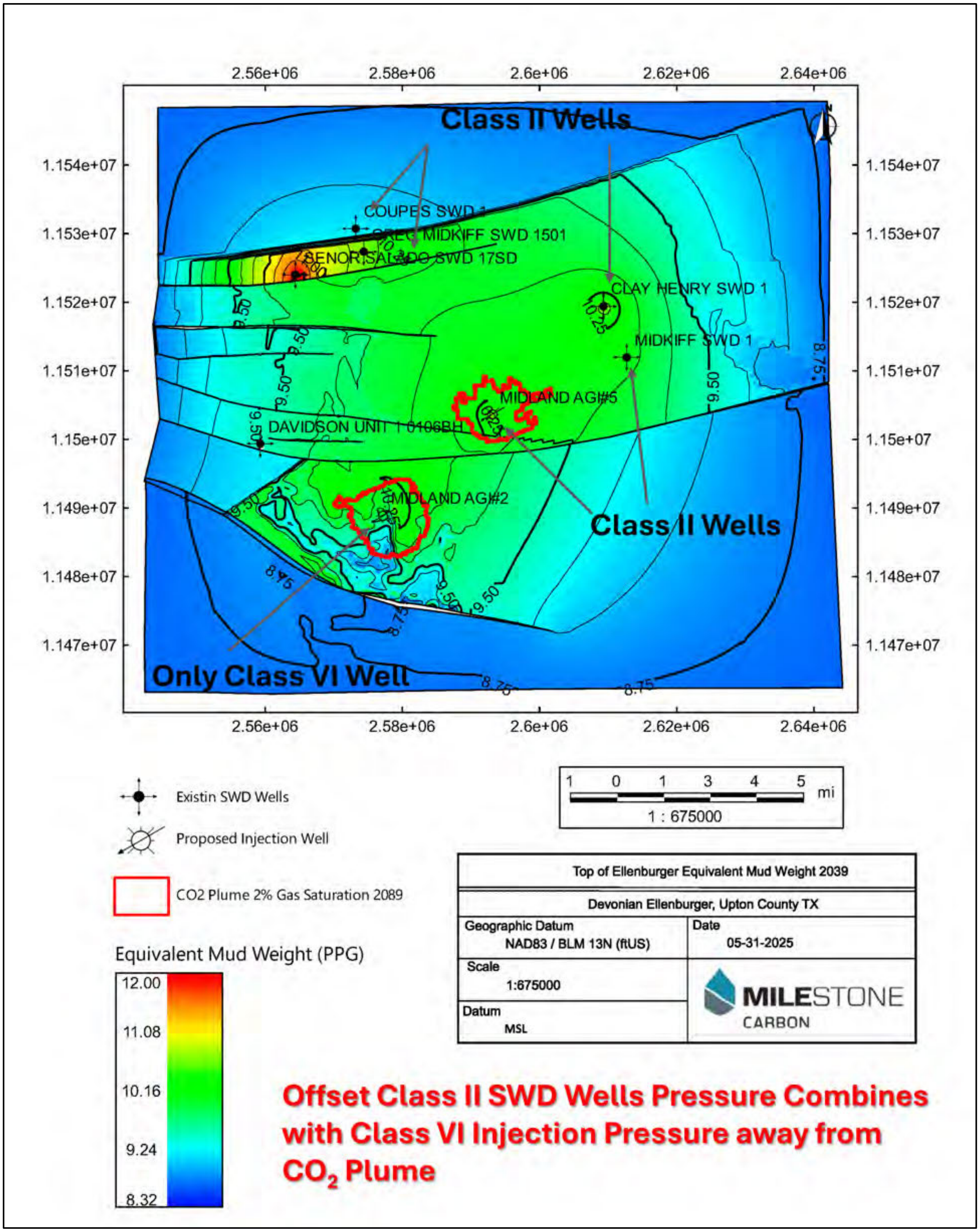

Figure 2-36: Maximum change in reservoir pressure at Top of Ellenburger Group

Maximum change in reservoir pressure across in 1st K-layer in the Injection Interval from model years 2027 (start of injection) to 2039 (end of injection). Contours shown in equivalent Mud Weight PPG. All wells perforated in Ellenburger. Faults baffle but do not completely seal off pressure changes.

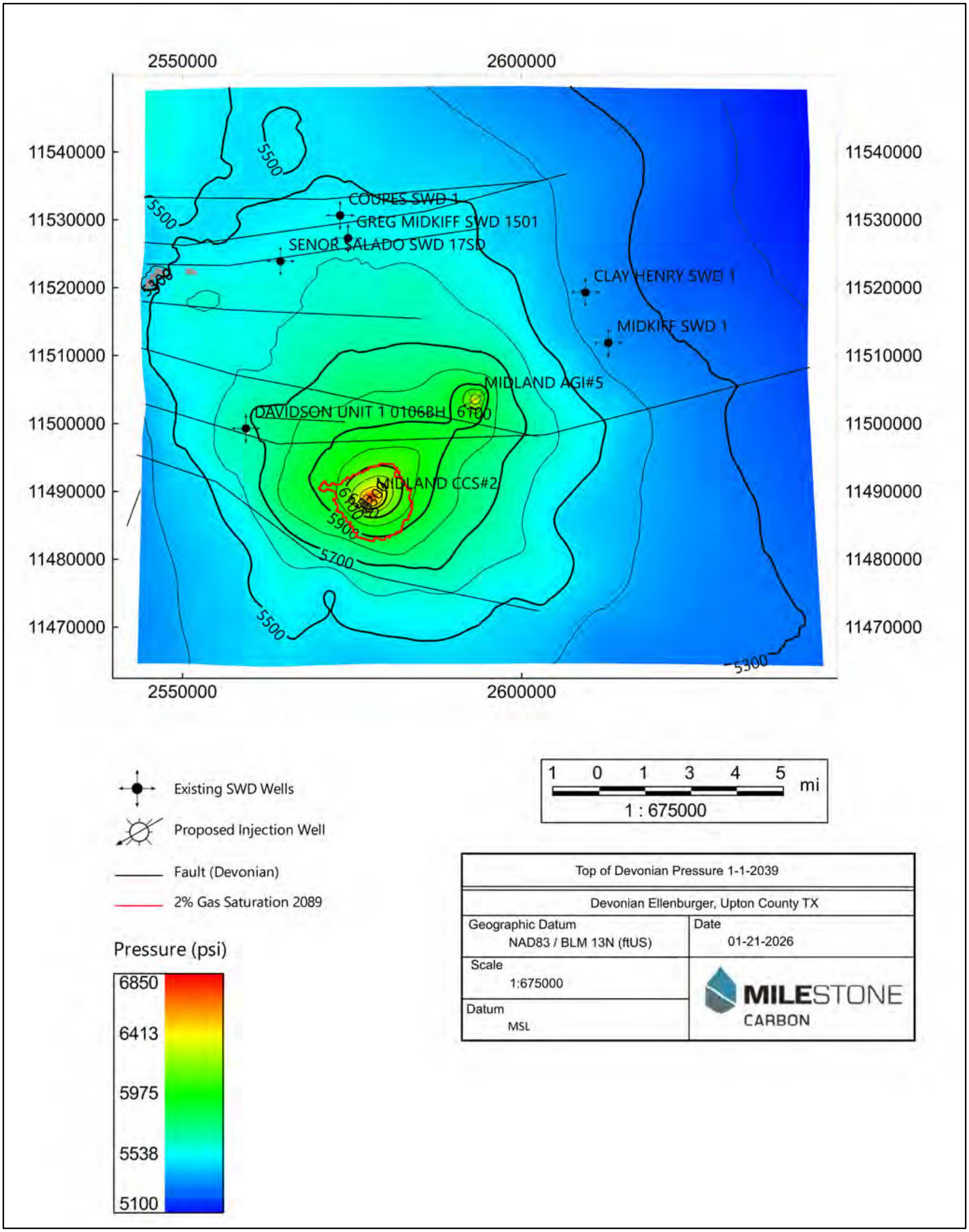

Figure 2-37: Maximum Pressure in PSI (2039) with Maximum CO_2 Plume (2089)

2.11 AoR Corrective Action Plans

2.11.1 Tabulation of Wells Within the AoR [40 CFR 146.82(a)(4); 40 CFR 146.84(c)(2)]

Milestone evaluated all oil and gas wells, water disposal wells, stratigraphic boreholes, dry holes, and plugged and abandoned wells within the AoR using data from proprietary and commercially operated databases. Well locations and associated attributes were sourced primarily from the Enverus DrillingInfo™ (DI) well database (**Sections 1.3 and 1.14**). The tables and maps reflect well data current as of October 2, 2024. Full maps of all features are provided in **Section 1.3**. Based on this review, zero (0) wells were found to penetrate the top seal or injection interval within the AoR.

For all identified wells, available records from the Railroad Commission of Texas (RRC) were downloaded and reviewed to confirm total depth and penetrated zones. Milestone also submitted a request to the RRC for non-digitized records and reviewed microfilm/microfiche files to confirm that no additional artificial penetrations exist within the AoR. Based on this review, 71 wells or potential wells were identified, though not all had complete records available.

Of these, 59 are existing oil and gas wells within the AoR (**Figure 2-38**):

- 26 Active, (including 3 shallow disposal wells)
- 12 Inactive,
- 13 Plugged and Abandoned,
- 1 Shut-in,
- 7 Unknown.

In addition, 12 wells were identified at various stages of development or permitting:

- 11 Expired permits,
- 1 Cancelled.

A comprehensive list of all wells within the AoR, including total depths and the deepest formation penetrated, is provided at the end of Permit **Section 1**, in **Appendix E**, and in the file **uploaded to GSDT** titled:

O&G Wells Summary Files (includes spreadsheet and shapefile)

All publicly available well files from the RRC for wells within the AoR and beyond, each of which Milestone reviewed to determine whether corrective action is necessary, are provided in the following file **uploaded to the GSDT**:

Well Files: *O&G Individual Well Files*

Wireline Logs: *O&G Raster Logs*

In addition, there are 87 water wells located within the AoR, a total of 155 water wells within 1 mile of the AoR. These water wells generally have depths of less than 300 feet. A list of the water wells within the AoR and within 1 mile outside the AoR can be found in the following file **uploaded to the GSDT:**

TWDB Water Well Summary Data

Individual well files from the Texas Water Development Board (TWDB) have been uploaded as well, in a file titled:

TWDB Individual Water Well Files

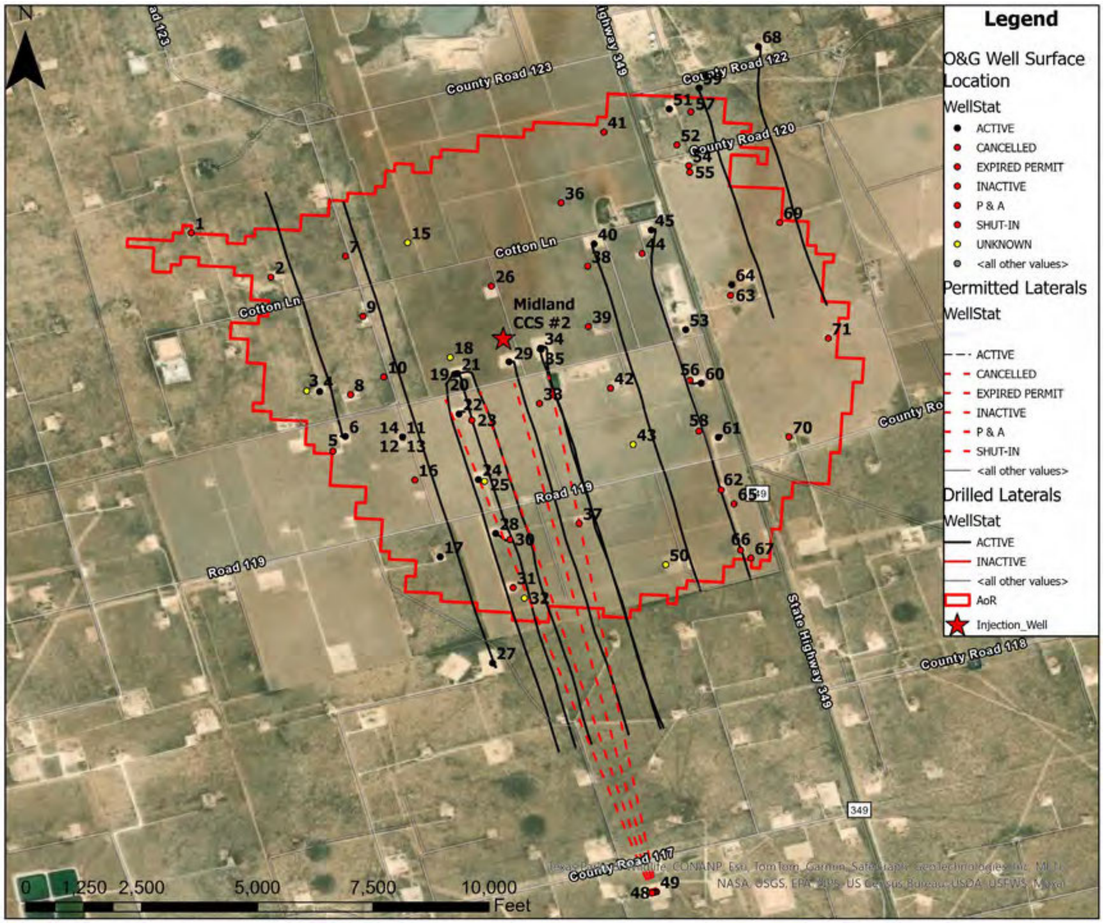

Figure 2-38: All Oil and Gas Wells Map of the AoR
See Section 1.14 for the index table.

2.11.2 Corrective Action Schedule [146.82 (a)(4)]

Wells that do not penetrate either the confining or injection unit pose negligible risk to underground sources of drinking water (USDWs) and therefore do not require corrective action. Based on available RRC records, zero (0) wells known to Milestone require corrective action. Milestone specifically positioned the Midland CCS #2 AoR to avoid any wells that penetrate the Top Seal or Injection Interval.

Out of an abundance of caution, Milestone identified all wells that penetrate the top seal or injection interval within 1 mile beyond the AoR boundary. **(Figure 2-39, Table 2-25).**

- Two (2) wells—Dusek 5 and Dusek 4—penetrate within 100 ft of the Devonian and are believed to penetrate the Barnett and possibly the upper portion of the Woodford.
- Two (2) additional wells—Windham R and JRS Farms 22—penetrate the Woodford Shale (primary top seal) and may approach within 50 ft of the top of the Siluro-Devonian injection unit. These wells were originally drilled to deeper intervals, likely as stratigraphic tests, but were later plugged back to produce from shallower Pennsylvanian and Permian zones.

None of these four wells fall within the AoR of the injection well, and none produce from deep Paleozoic intervals such as the Ellenburger or Devonian. Notably, Milestone positioned the Midland IZM #1 in the direction of JRS Farms 22 to assist with monitoring, as the plume is expected to migrate updip to the southeast.

Given their proximity to the AoR, Milestone carefully reviewed records for all four wells. While wireline logs do not confirm penetration into the Devonian, drilling records and completion reports using driller-reported depths indicate that some wells approached the contact before being plugged back into the Woodford. The plugged-back total depth (PBTD) for each is shown on wellbore diagrams and recorded in the RRC database. The difference between reported TD and the top of the Devonian is summarized in **Table 2-25**.

Due to the distance from the injection well and the low permeability of the upper Devonian packstones, it is unlikely that CO_2 will migrate to these wells over the life of the project. As shown in **Section 2.6**, the majority of the injectate remains in the lower Devonian and Ellenburger, where fracture concentration and permeability are significantly higher.

Milestone will continue to assess the potential risk posed by these wells as the AoR is recalculated following the acquisition of 3D seismic and stratigraphic test well data. Complete RRC well files for these penetrations are provided in the *Potential Penetration outside AOR appendix file*. For additional information on other wells, please see *O&G Well Individual Files*

Table 2-25: Wells within a 1-mile buffer of the AoR that potentially penetrate Top Seal
Note, zero of these wells occur within the AoR

Well Name	Well No.	API14	Operating Company	Total Depth (ft, TVD)	Devonian Top (ft, TVD)	Estimated Distance Above Devonian (ft)
WINDHAM "R"	3	4246139609	PIONEER NATURAL RESOURCES	12,376	12,347	-29
DUSEK	5	4246137895	PIONEER NATURAL RESOURCES	12,230	12,293	63
DUSEK 4	4	4246137841	PIONEER NATURAL RESOURCES	12,200	12,243	43
JRS FARMS 22	1	4246137740	PIONEER NATURAL RESOURCES	12,152	12,141	-11

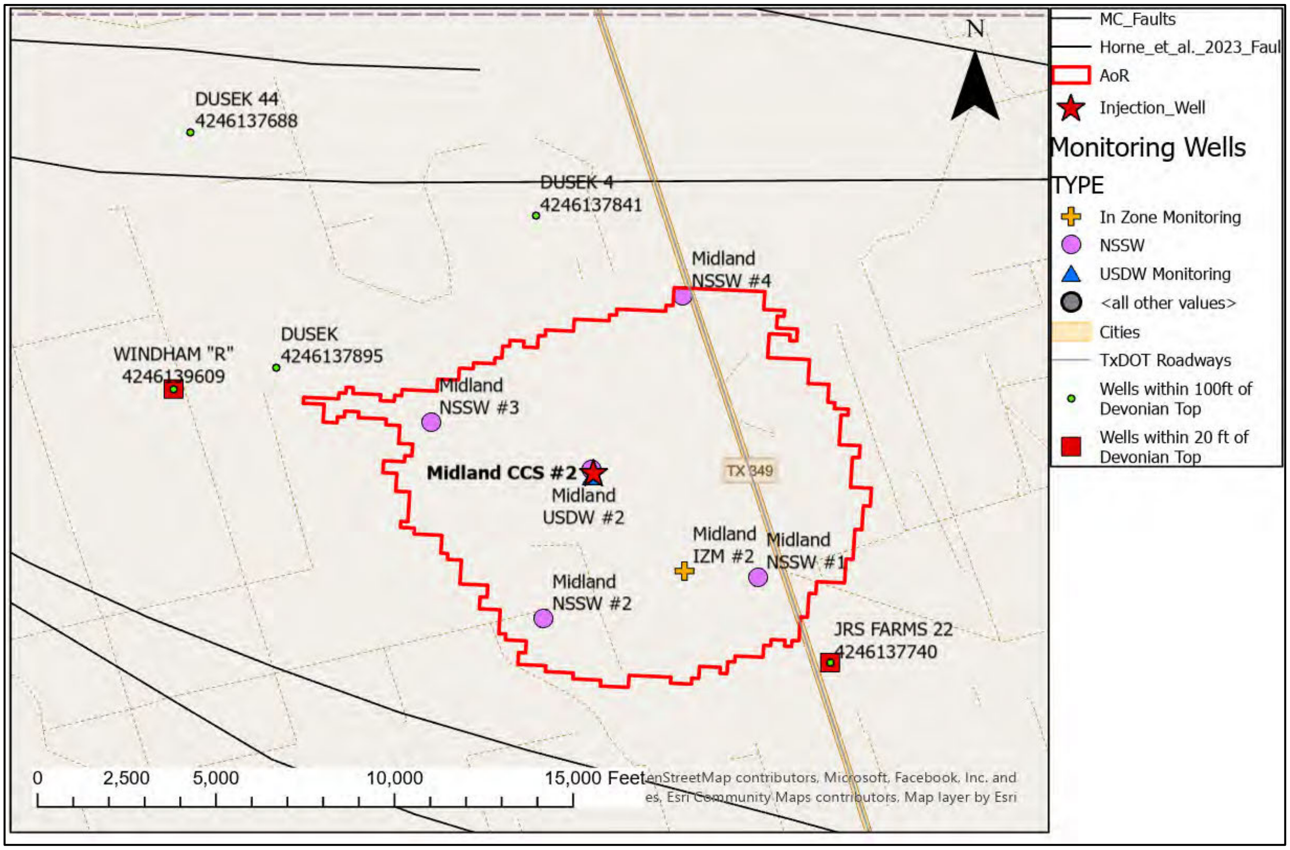

Figure 2-39: **Wells Near the AoR that Potentially Penetrate Woodford (Green) or Devonian (Red)**

A cross-section of the wireline logs of the four wells is shown in **Figure 2-40**. Note the lack of Devonian tops on the cross section, because the wireline logs do not observe the contact.

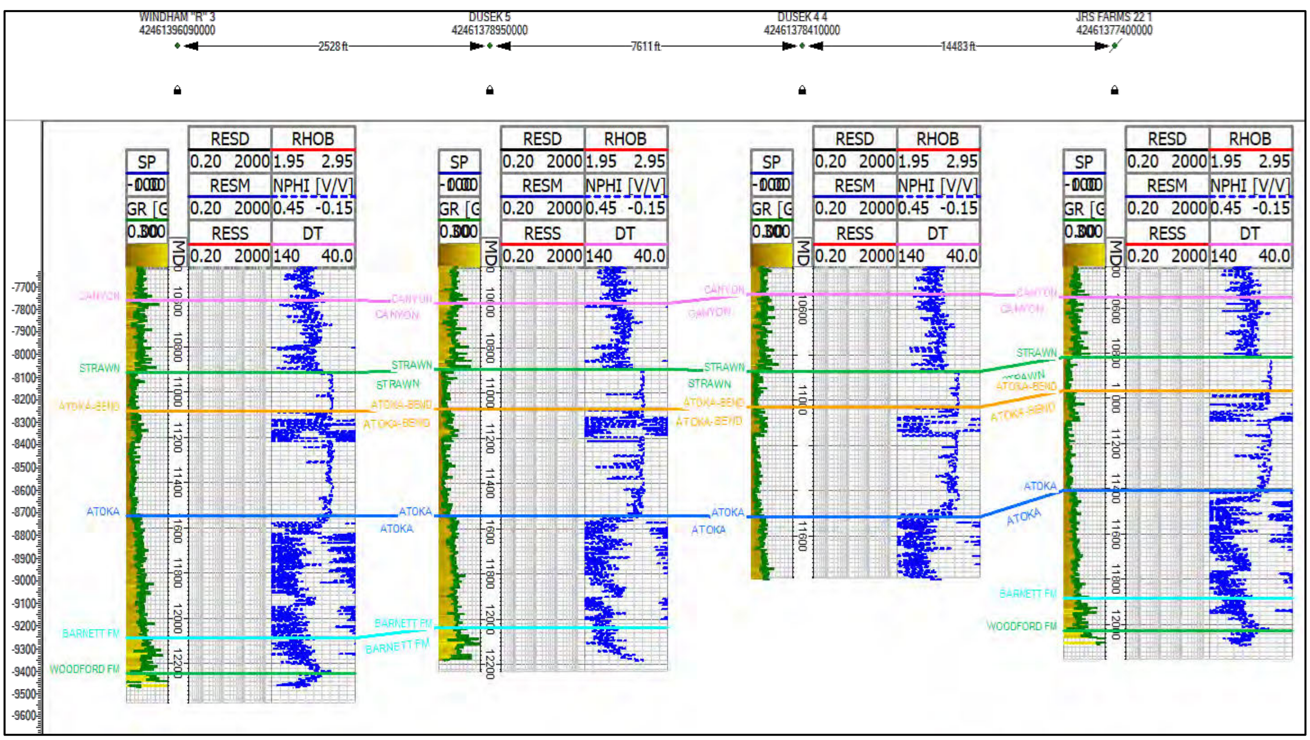

Figure 2-40: Cross Section of Wells Near the AoR that Potentially Penetrate Woodford

Wellbore diagrams for the JRS Farms 22 and Windham R wells are provided in **Figure 2-41** and **Figure 2-42**, respectively. Note the Plugged Back Total Depth (PBTD) at the bottom of each well. Even if these wells hypothetically penetrated the Devonian, both were plugged back into the Woodford or higher formations and are unlikely to come into contact with injected CO_2, as they are located outside the AoR.

Although these wells fall outside the AoR, Milestone is including the wellbore diagrams for EPA review to demonstrate that these wells have been evaluated and that appropriate remedial actions will be taken if the plume unexpectedly migrates toward them. The plume and pressure monitoring plan is provided in **Section 6** of the permit application, which includes additional details on monitoring strategies and frequency.

Well Name:	JRS Farms 22 #1
API:	42-46137740
State:	TX
County:	Upton
Field:	Spraberry
Elevation:	2,793'
Depth (TVD):	12,152'
Texas Central NAD 83	
Lattitude:	31.6009339°
Longitude:	-101.9718755°

Casing Program

		OD (in)	Weight (lb/ft)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	48	17 1/2	0	464	0
2	Intermediate:	8 5/8	32	11	0	4,506	516
3	Production:	5 1/2	17	7 7/8	0	12,152	5,650

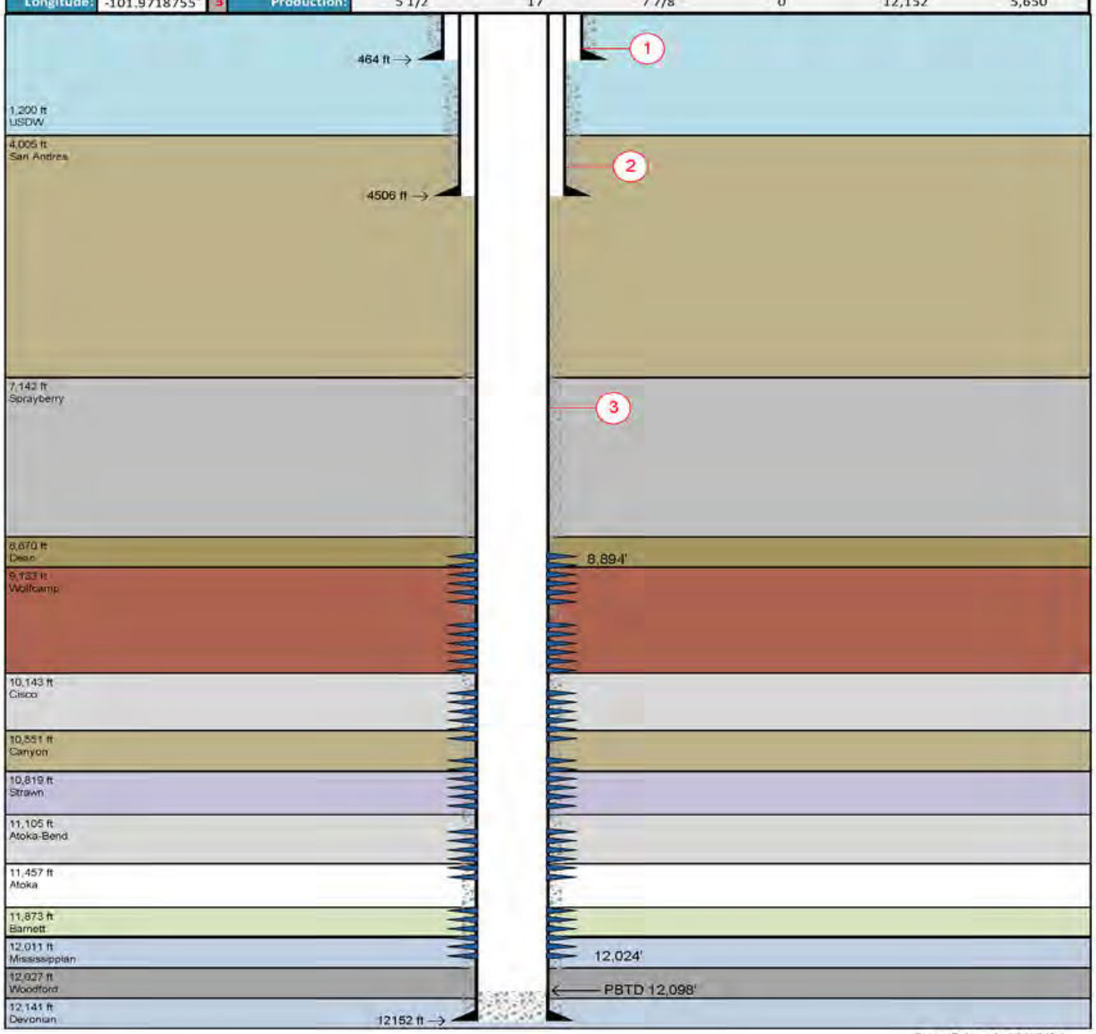

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Figure 2-41: JRS Farms 22 Wellbore Schematic (Not to Scale)

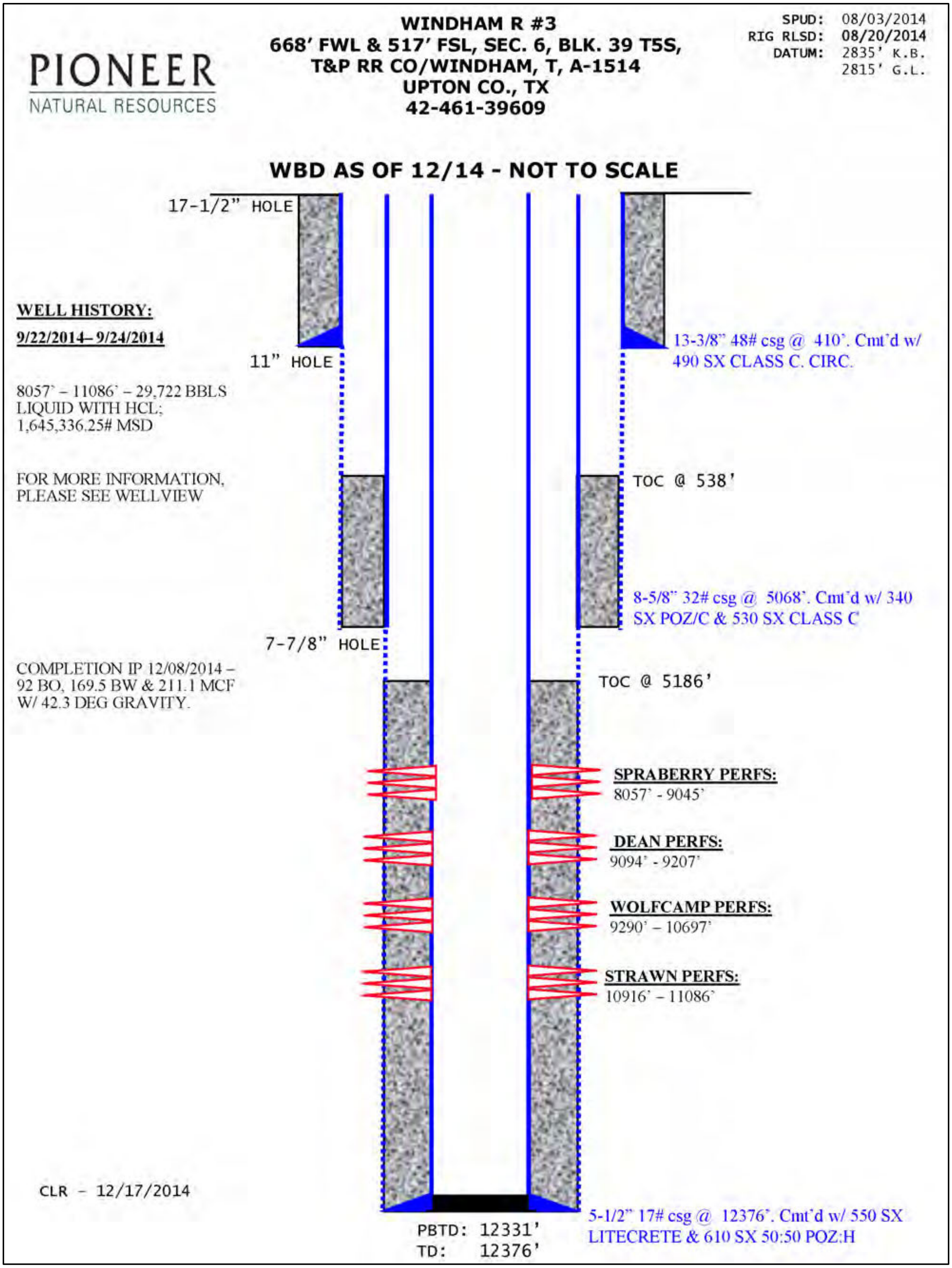


Figure 2-42: Windham R #3 Wellbore Schematic (Not to Scale)

2.11.3 Re-Evaluation Schedule and Criteria

Milestone will reevaluate the Area of Review (AoR) at least once every five (5) years during both the injection and post-injection phases.

The reevaluation procedure will be based on data collected between reevaluations and the well conditions at the time of review. Measured data will include injection rates, pressures, and other relevant operating conditions from the Midland CCS #2 Well, which will be used to inform and update the dynamic model.

History matching will be conducted by inputting recorded injection data into the dynamic model and adjusting model parameters to align with observed pressures. This process calibrates and validates the model to actual site conditions. In addition to history matching the Midland CCS #2 Well, performance data from offset saltwater disposal (SWD) wells, including the Davidson Unit #1, will continue to inform model refinements.

Sensitivity analysis will be performed to identify the parameters that most significantly influence plume behavior and AoR extent. Input parameters will be modified incrementally to assess their impact on predicted plume size and AoR boundaries.

Each AoR reevaluation will include discussion of the following:

- Changes in monitoring or operational data since the previous evaluation.
- How updated monitoring and operational data (e.g., injection rate, pressure) were used to revise the geologic model and computational simulations.
- Any triggers that warranted an unscheduled AoR reevaluation.

If any observations or measurements are determined to materially affect plume size or AoR extent, Milestone will update the Model and perform a reevaluation. Any newly identified wells within the updated AoR will be assessed for corrective action requirements. If needed, corrective action will be undertaken in accordance with applicable federal, state, and local regulations.

Milestone will submit either an amended AoR and Corrective Action Plan or documentation supporting that no changes are required, based on modeling results and monitoring data. Any such events will be discussed with the UIC Program Director to determine whether a formal AoR reevaluation is necessary.

- If an unscheduled reevaluation is triggered, Milestone will take the following steps:
- Evaluate the static model assumptions in light of new data or measurements.
- Run the updated static model and compare outputs to prior predictions.
- Evaluate the dynamic model assumptions using the new data.
- Run the updated dynamic model and compare results to previous simulations.

See **Section 6** for more information on the testing and monitoring program, and **Section 10** for details on emergency criteria and response.

2.11.4 Re-evaluation Events

Milestone Environmental recognizes the importance of defining clear, enforceable triggers for AoR re-evaluation. However, because subsurface pressure and plume migration behavior are subject to spatial heterogeneity, monitoring uncertainty, and model uncertainty, re-evaluation triggers cannot be defined as rigid, single-value thresholds without professional interpretation of baseline data. Examples of events that may trigger an unscheduled AoR reevaluation, with guidance from the UIC Program Director are found in **Table 2-26**. Milestone will be pro-active in working with the UIC team to determine when an AoR re-evaluation is necessary.

Table 2-26: Re-evaluation Trigger Events

Parameter	Trigger Type	Quantitative Threshold	Action
Earthquake	Seismicity Monitoring Alert	Magnitude 3.5+ within 10 km	Notify agency, shut-in well, review AoR and Pressures along faults; see ERRP for earthquake procedures.
CO_2 Saturation	Wireline Logging	CO2 Saturation +/- 25% from modeled amount at IZM #1 or CCS #2	Notify agency, Model Update, AOR reassessment
Leak Event	Leak Detected	More than 100 tonnes leaks out of injection zone	Notify agency, shut-in well, evaluate potential leakage pathways, review AoR and Pressures, AoR reassessment
Surface pressure	SCADA Monitoring Alert	≥500 psi above predicted	Notify agency, internal review
Surface pressure	SCADA Monitoring Alert	≥1,000 psi above predicted, sustained	Notify agency, Model update, AoR reassessment
CO_2 plume area	Technical evaluation	≥20% greater than modeled CO_2 plume area is calculated	Notify agency, AoR reassessment
CO_2 plume	Indirect Monitoring Alert	Any detected CO_2 plume migration >2% saturation beyond 2039 AoR during injection period	Notify agency, Model update, AoR reassessment
TDS	Water Testing Monitoring Alert	≥20% deviation from baseline of Major Cation and Anions	Notify agency, Review sampling, Evaluate potential leakage pathways, AoR Reassessment
TDS	Water Testing Monitoring Alert	≥25% change in other properties such as pH or sustained deviation inconsistent with model	Notify agency, Review Sampling, Evaluate potential leakage pathways, AoR Reassesment
CO_2 detected in USDW	Water Testing Monitoring Alert	Unexplained CO2 discovered in ground water in quantities greater than 500 mg/L above baseline	Notify agency, shut-in well, evaluate potential leak pathways, review AoR and Pressures, AoR reassessment

Milestone will discuss any such events with the UIC Program Director to determine if an AoR revaluation is required. If an unscheduled reevaluation is triggered, Milestone will perform the steps described at the beginning of this section of this Plan. Milestone will also monitor trends in measurements and advise the agency of any going concerns. In addition to the triggers above, Milestone would also like to provide additional guidance regarding trends below.

Consistent with the EPA Class CI Testing and Monitoring Guidance, Milestone evaluates the following trends that may indicate potential fluid leakage. **If two or more of these trends** (relative to baseline data) are noted over a period of three or more sampling events, Milestone will initiate further coordination with EPA or TRRC to assess the potential for fluid leakage above the confining zone and if an AoR re-evaluation is necessary. Indicators of potential fluid leakage include:

- Increasing TDS: An increasing TDS trend may indicate that native brines have migrated from the injection zone, or an intervening zone, into the monitored zone. A change in the overall TDS trend may indicate fluid exchange between adjacent formations.

- Increasing CO2 concentration: An increase in the concentration of dissolved CO2 may indicate leakage of the dissolved-phase plume into the monitoring zone. Increasing CO2 concentrations may also be observed due to other factors, including increasing groundwater recharge. These other factors may be evaluated to ascertain if the observed increasing CO2 concentrations are due to migration from the injection zone.

- Decreasing pH: A decreasing pH trend may indicate migration of carbonic acid and other fluids into the monitoring zone. Similar to increasing CO2 concentrations, other factors may be evaluated that would cause an observed decrease in pH.

- Increasing concentration of injectate impurities: An increase in the concentration of any impurities in the injectate may be indicative of injectate migration into the monitoring zone.

- Increasing concentration of leached constituents: The presence of CO2 may leach certain inorganics from the formation matrix due to lowered pH. Increasing trends may be indicative of fluid migration.

- Increased reservoir pressure and/or static water levels.

Trends will be evaluated using the Mann-Kendall statistical test, following standard methods described in EPA (2009). A trend will be considered significant if it meets the following criteria:

- For increasing trends: The Mann-Kendall test indicated an upward trend at the 95% confidence level and the most recent value is at least 25% higher than baseline.

- For decreasing trends (i.e., pH): The test indicated a downward trend at the 95% confidence level and the most recent value is at least 25% lower than baseline.

- In addition, a change in the signature of dissolved groundwater constituents in the monitored zone as compared to that of the injection zone or confining zone may indicate leakage. The anion/cation signature may be evaluated through the construction and use of ion diagrams, including piper and stiff diagrams.

2.12 Additional Pressure Maps

To aid in the review of the dynamic model, Milestone has included the following maps from **Figure 2-43 to Figure 2-54** showing pressure at various time steps and various k-layers.

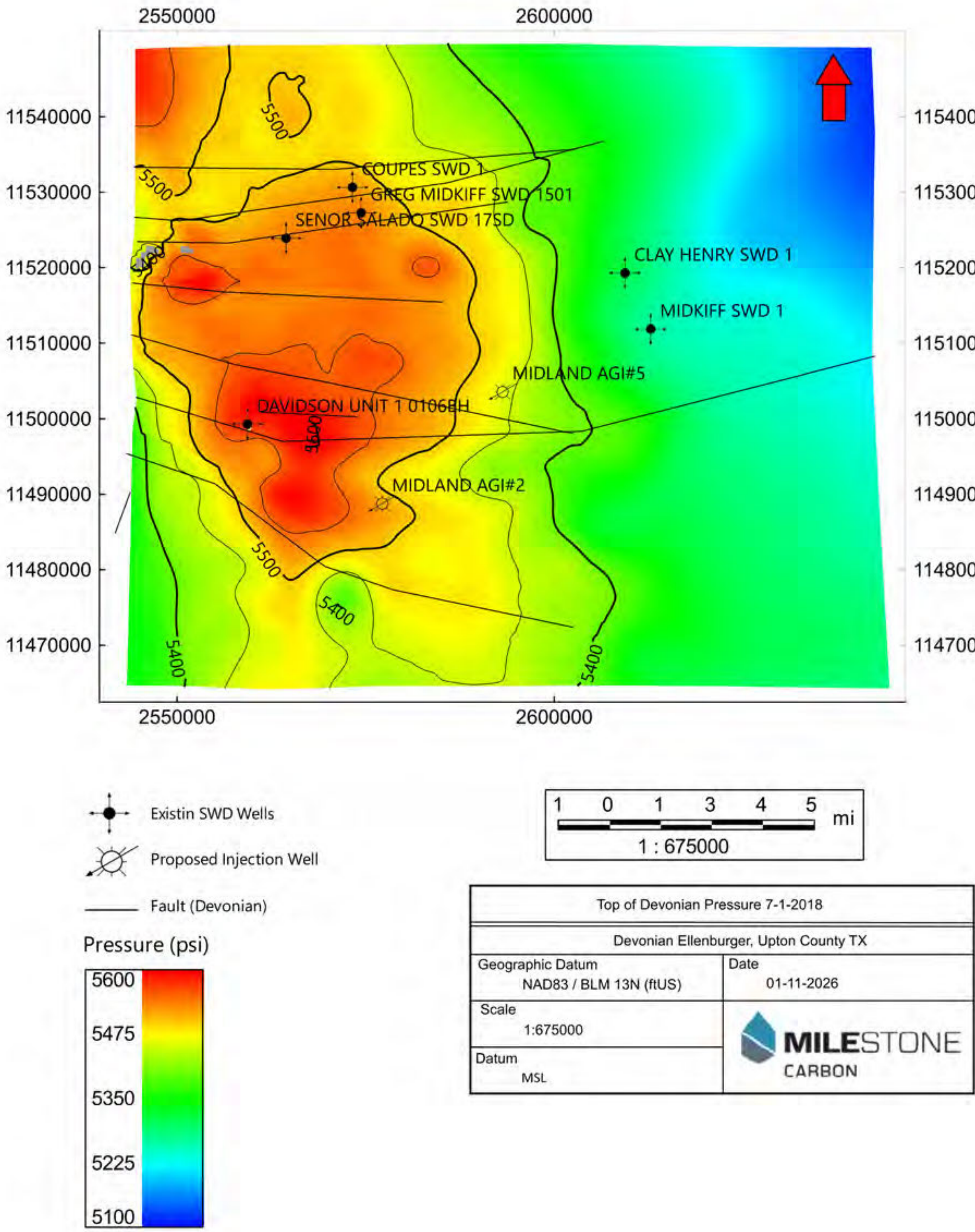


Figure 2-43: Pressure in psi at initial conditions, Top of Devonian, in 2018 prior to any injection, SWD or CO2

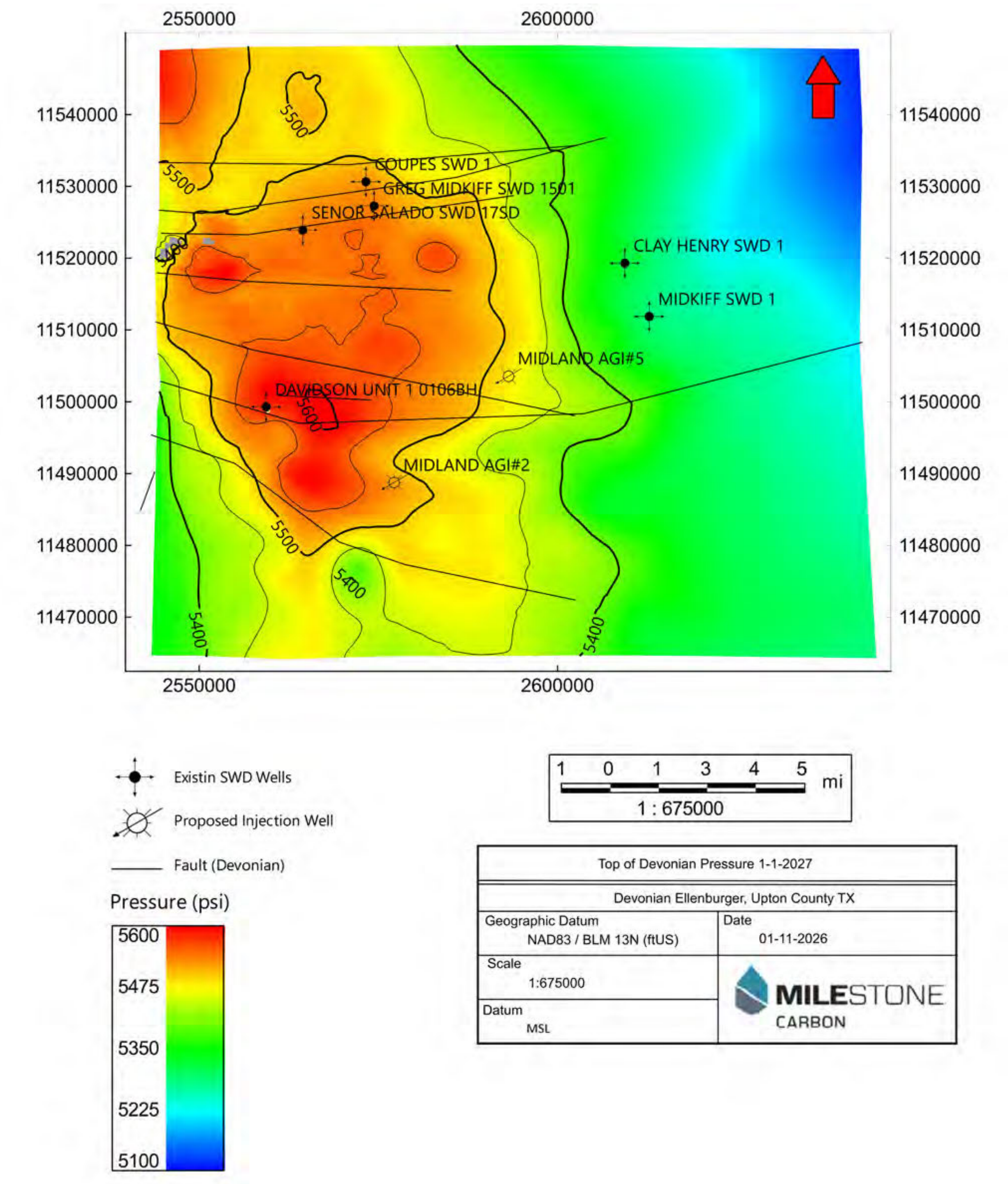


Figure 2-44: Pressure in psi, Top of Devonian, in 2027, just prior to CO2 injection commencing

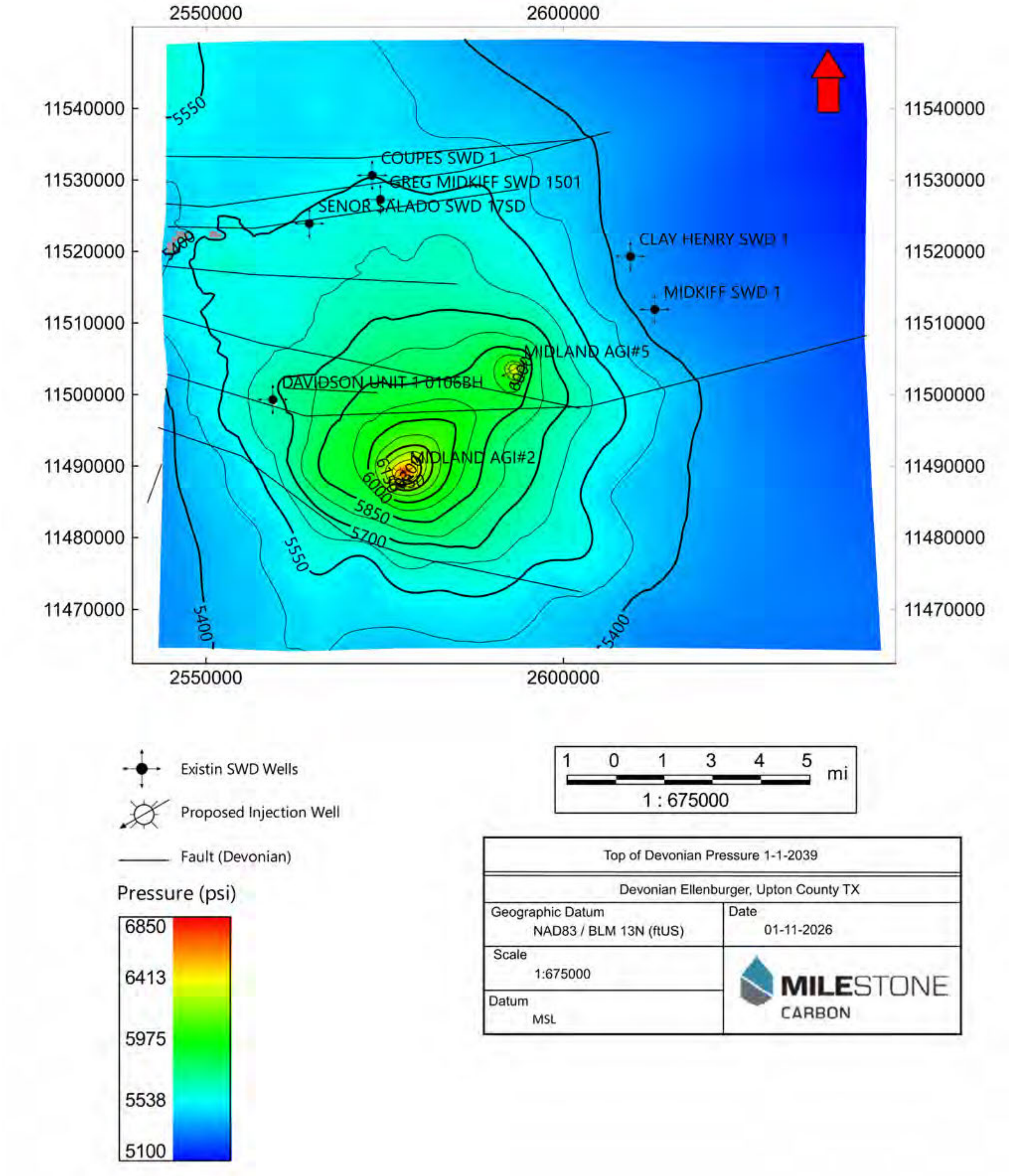


Figure 2-45: Pressure in psi, Top of Devonian, in 2039 when injection terminates

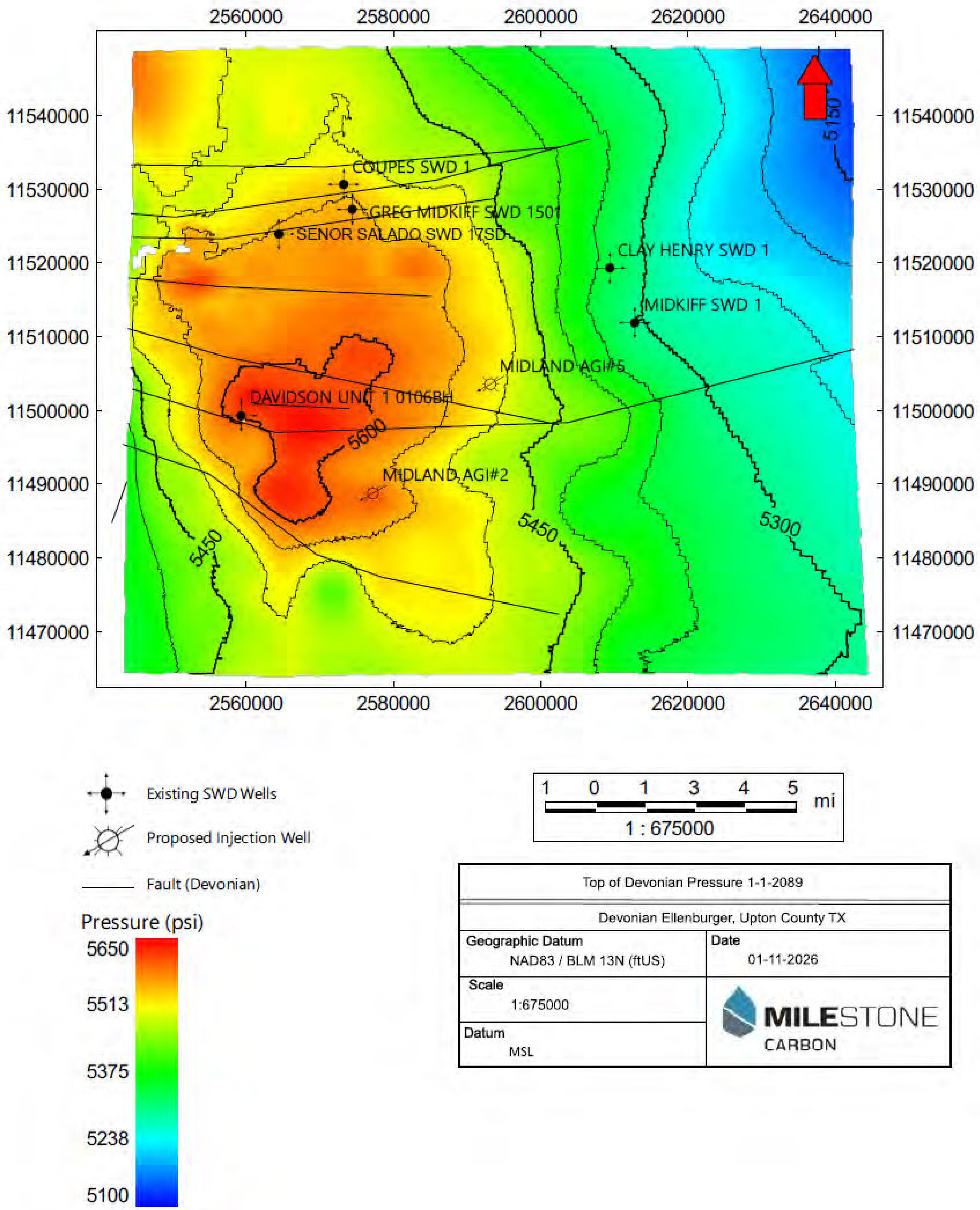


Figure 2-46: Pressure in psi, Top of Devonian, in 2089 at the end of the PISC period

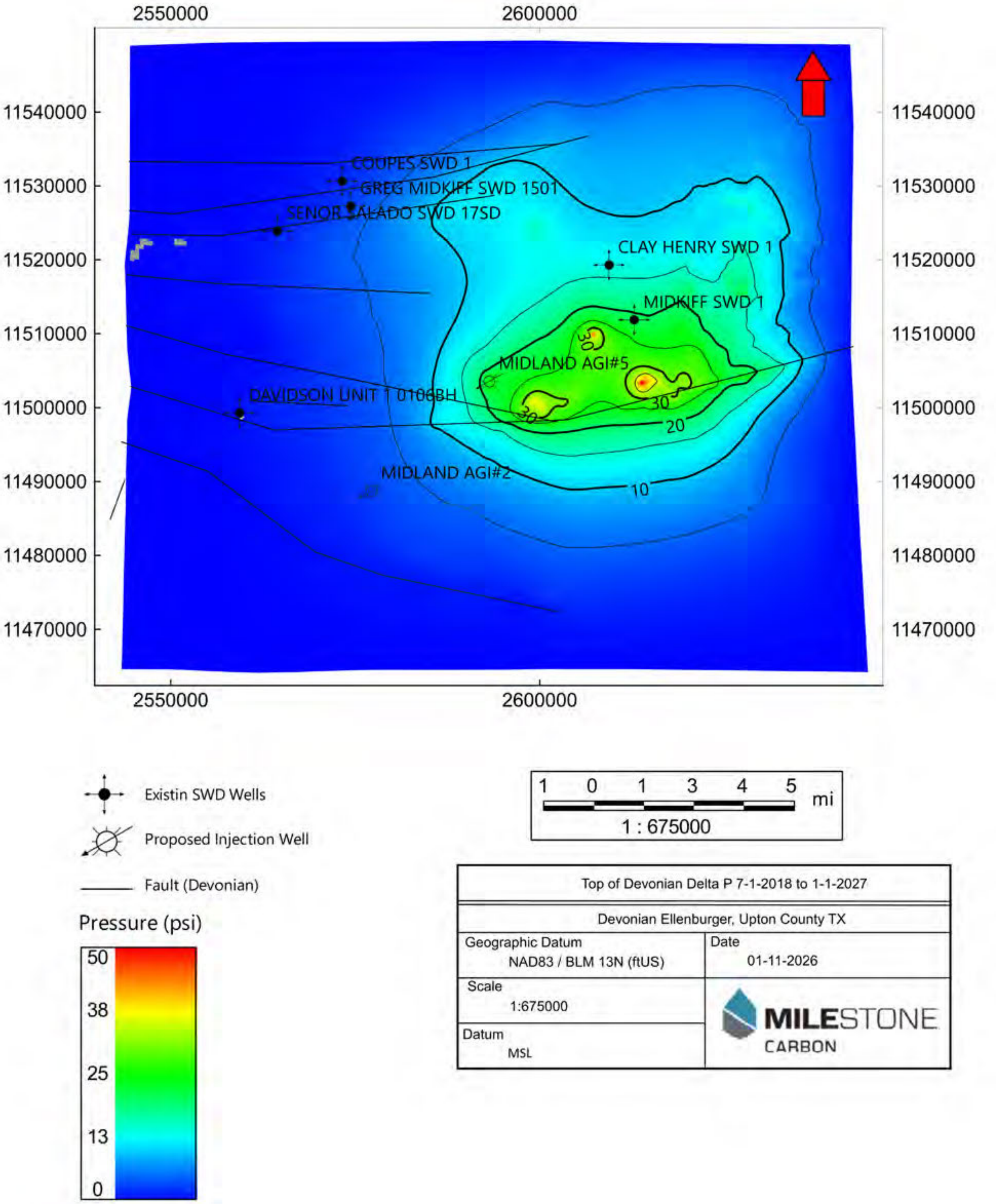


Figure 2-47: Pressure differential in psi, Top of Devonian, from start of simulation in 2018 to start of CO2 injection in 2027

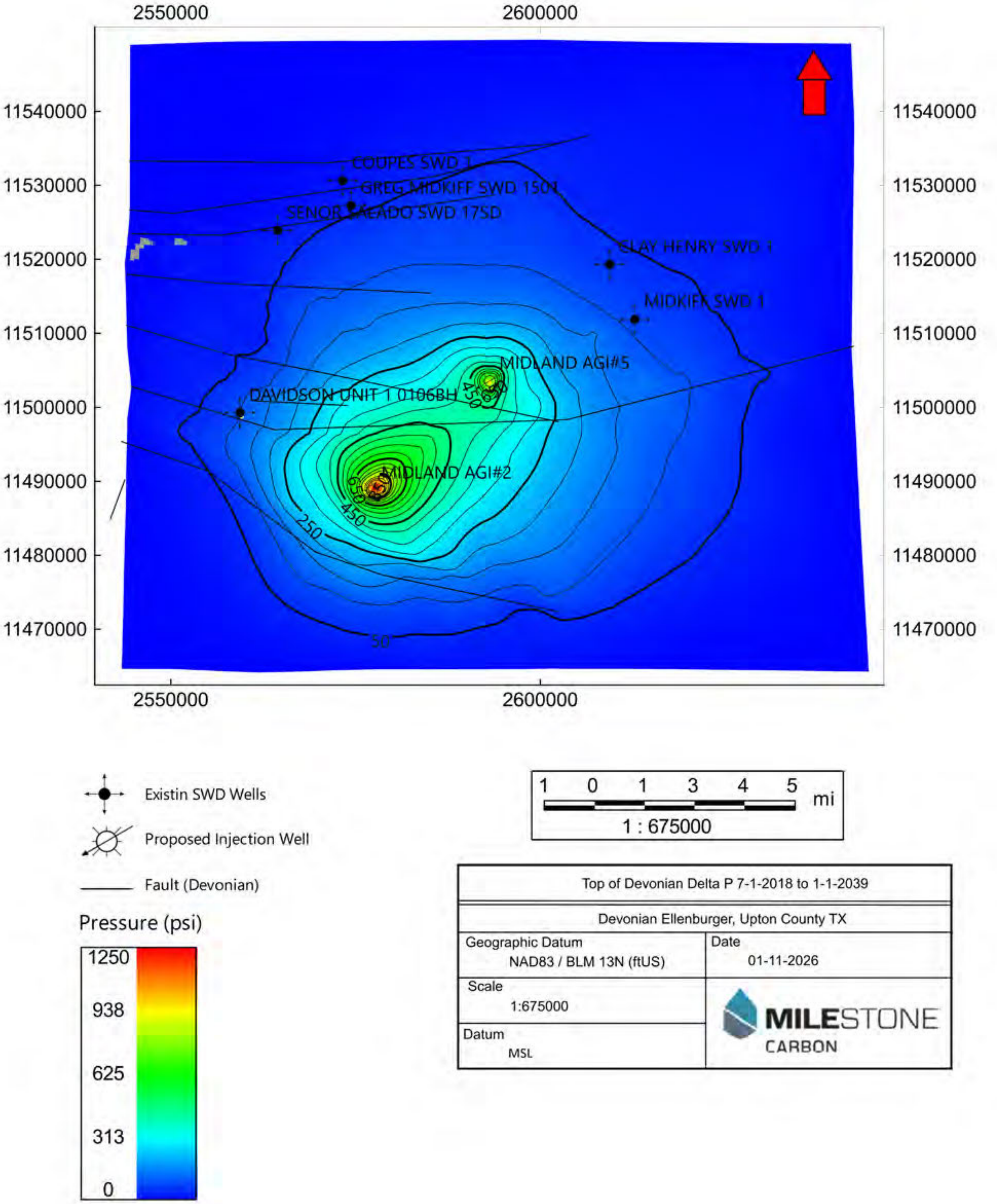


Figure 2-48: Pressure differential in psi, Top of Devonian, from start of simulation in 2018 to termination of injection of CO2 in 2039

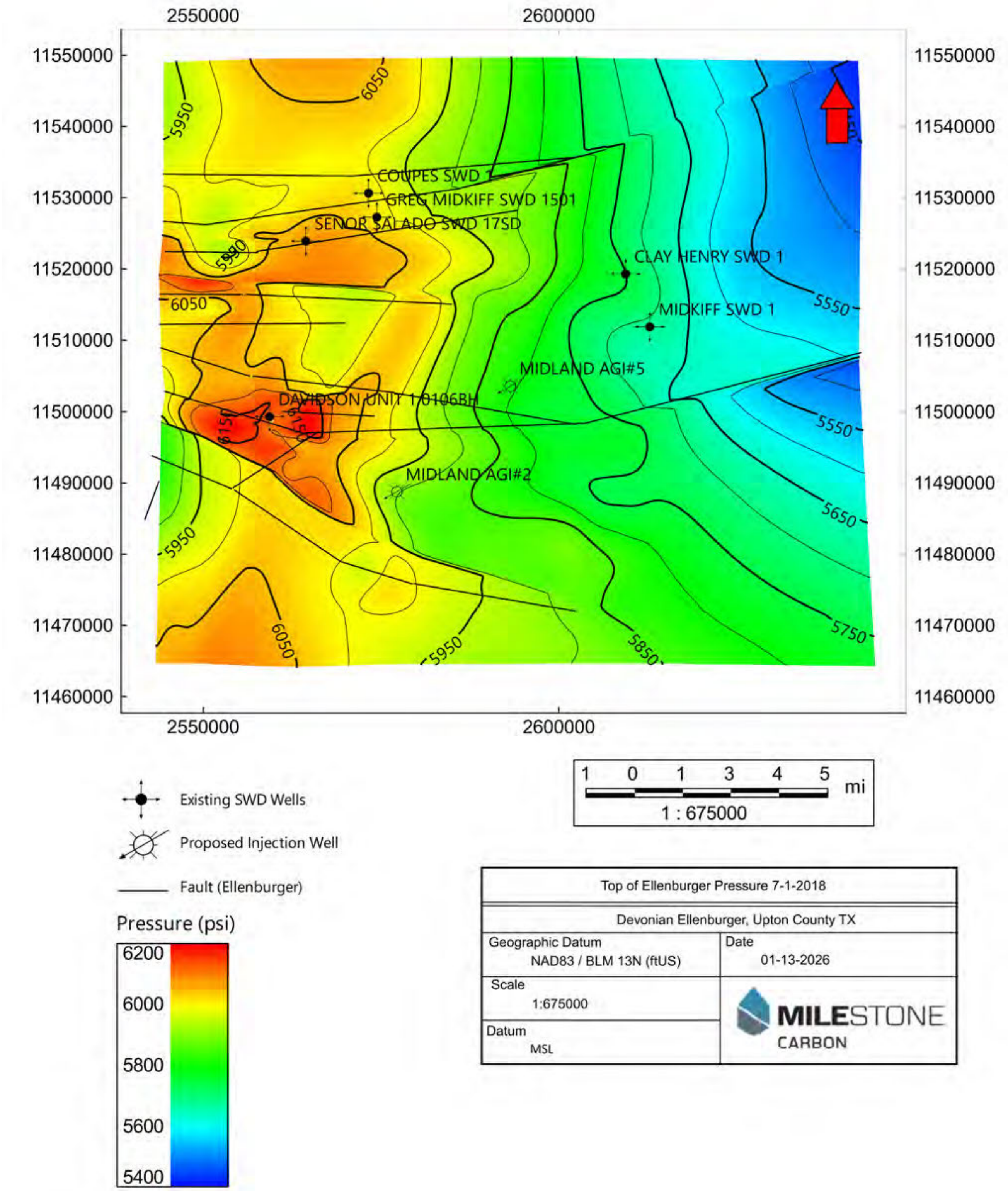


Figure 2-49: Pressure in psi, Top of Ellenburger, at the start of simulation in 2018, prior to any injection, SWD or CO2

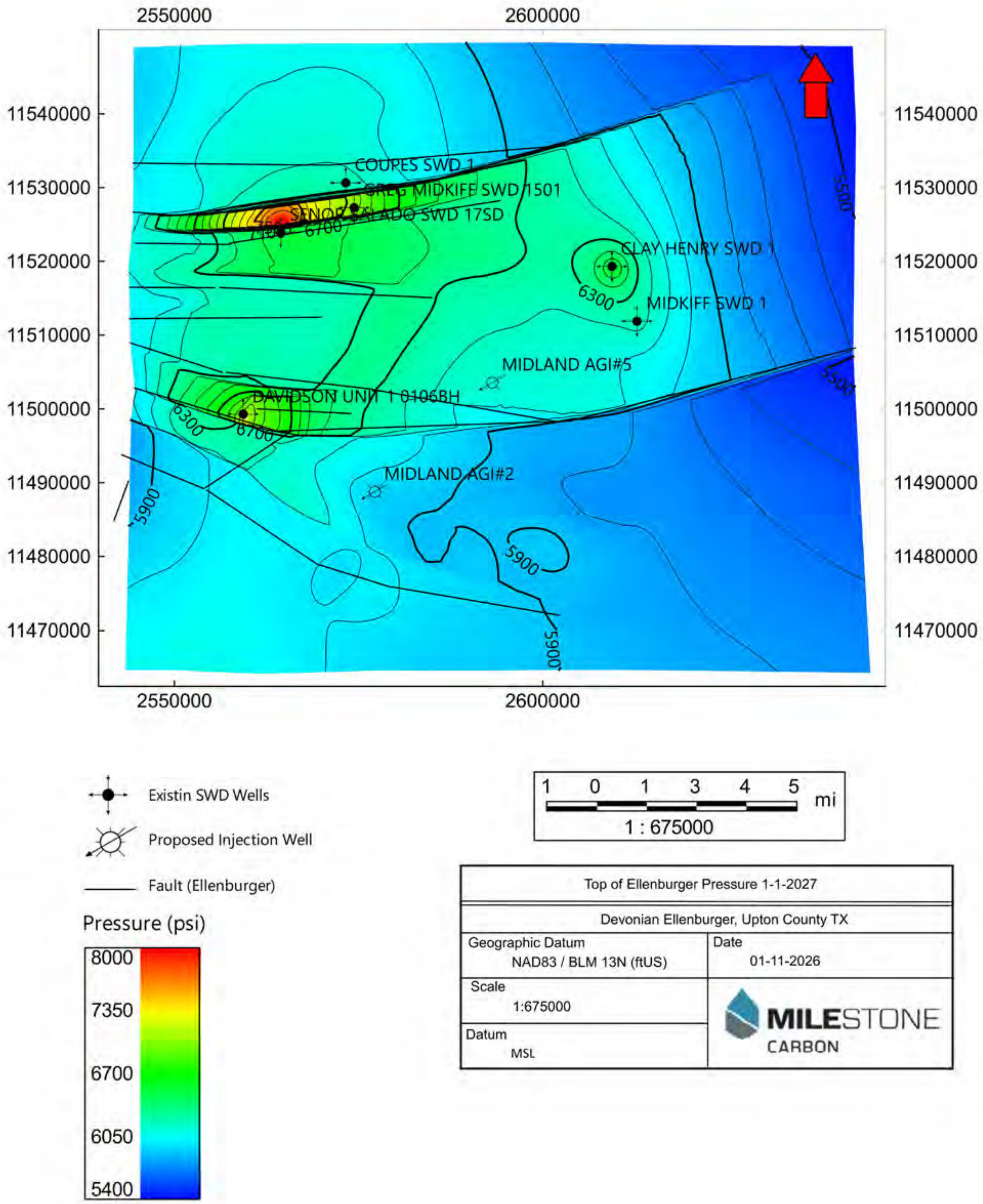


Figure 2-50: Pressure in psi, Top of Ellenburger, just prior to of CO2 injection commencing in 2027

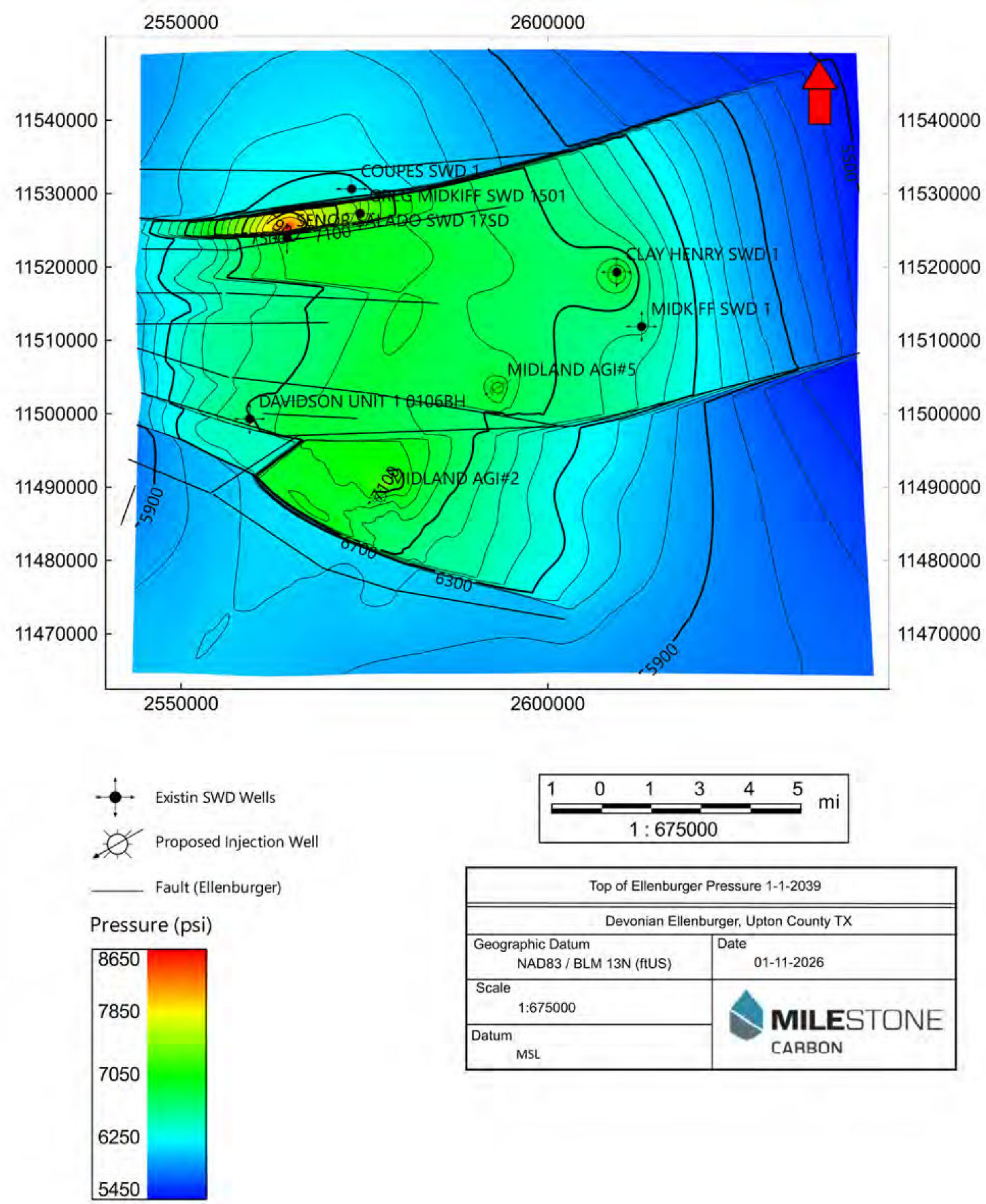


Figure 2-51: Pressure in psi, Top of Ellenburger, at the termination of CO2 injection in 2039

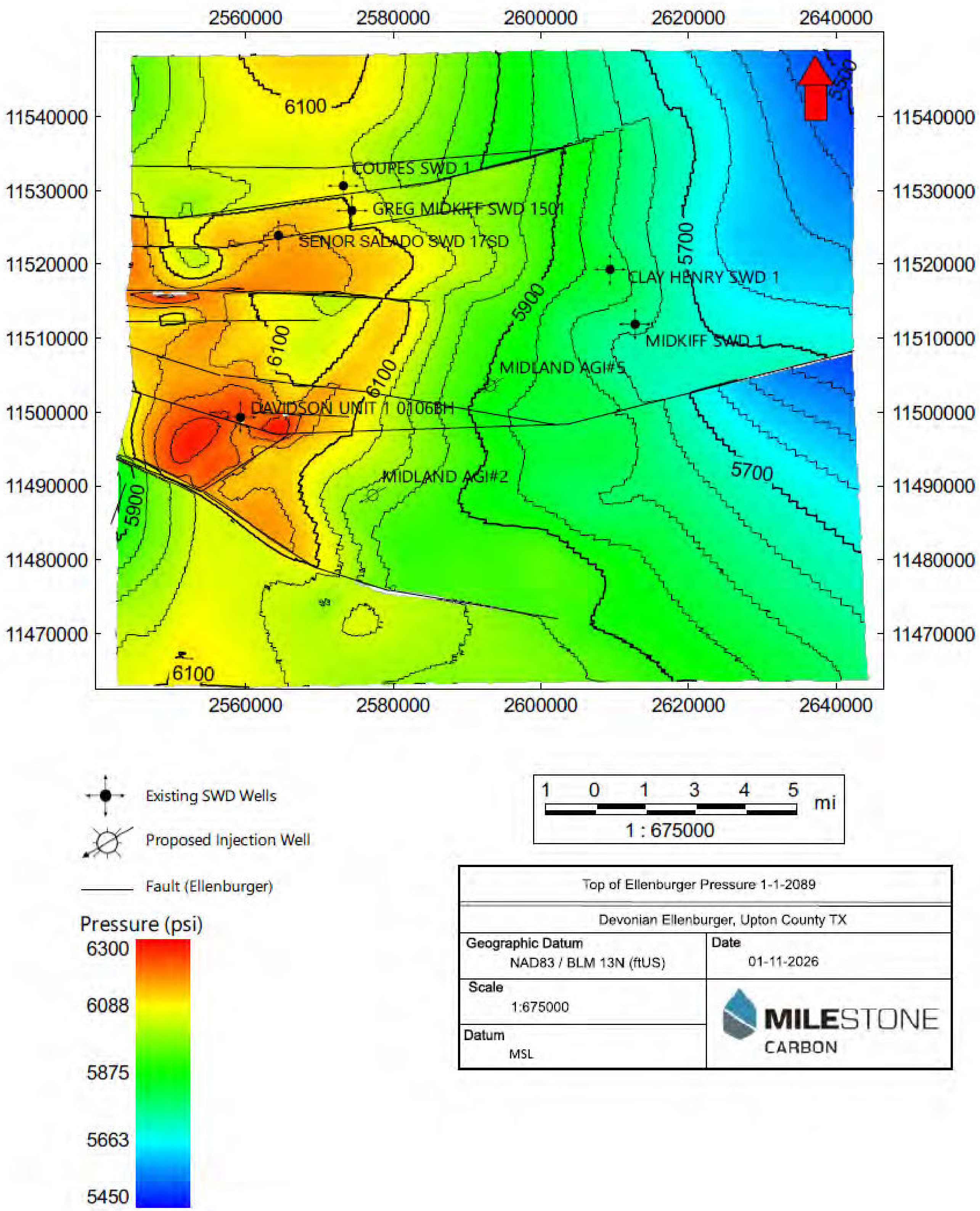


Figure 2-52: Pressure in psi, Top of Ellenburger, end of PISC period in 2089

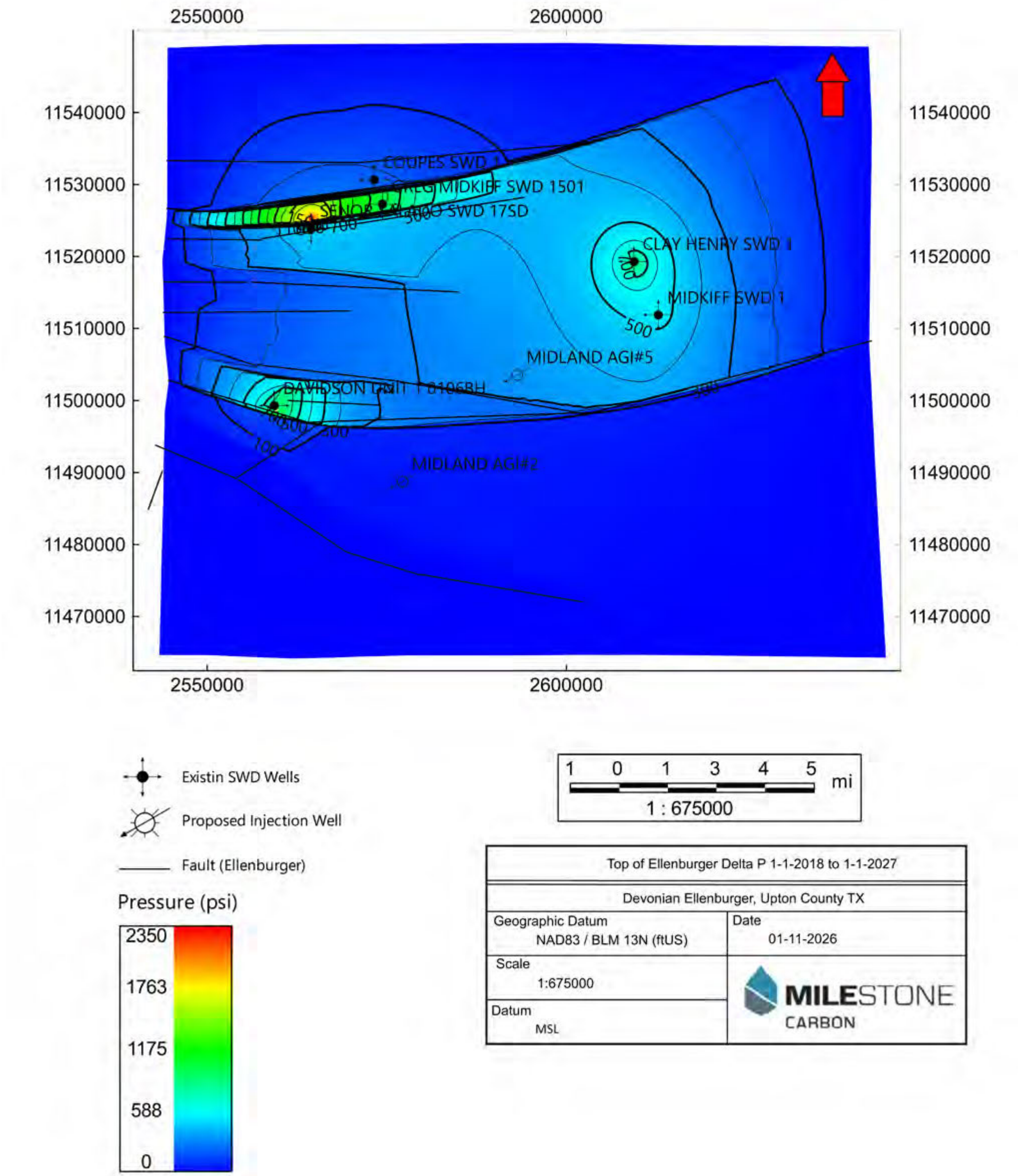


Figure 2-53: Pressure differential in psi, Top of Ellenburger, from start of simulation in 2018 to the start of CO2 injection in 2027

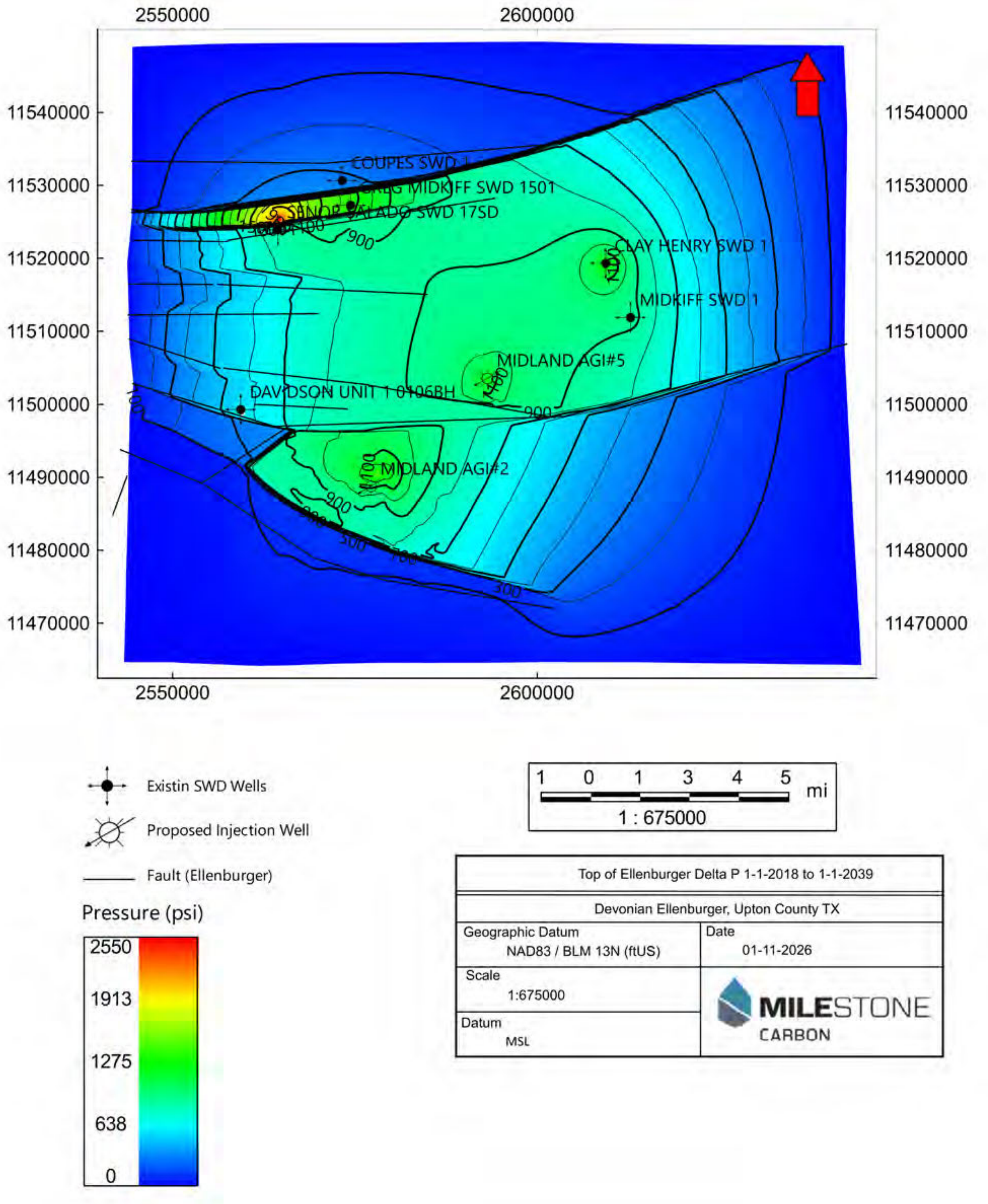


Figure 2-54: Pressure differential in psi, Top of Ellenburger, from start of simulation in 2018 to the end of CO2 injection in 2039

2.13 Plume and Pressure TRRC Time Periods

To satisfy Statewide Rule TAC §5.203 (d)(1)(A) requiring that using computational modeling the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods. Milestone has prepared the maps in **Figures 2-55** through **Figure 2-58.** A summary of the area and radii of the plume at each time step is illustrated in **Table 2-27**. The vertical extent of the plume is confined within the injection interval. See **Section 2.6** for cross sections of the plume over time.

- five years after initiation of injection;
- from initiation of injection to the end of the injection period proposed by the applicant; and
- from initiation of injection until the movement of the CO_2 plume and associated pressure front stabilizes.

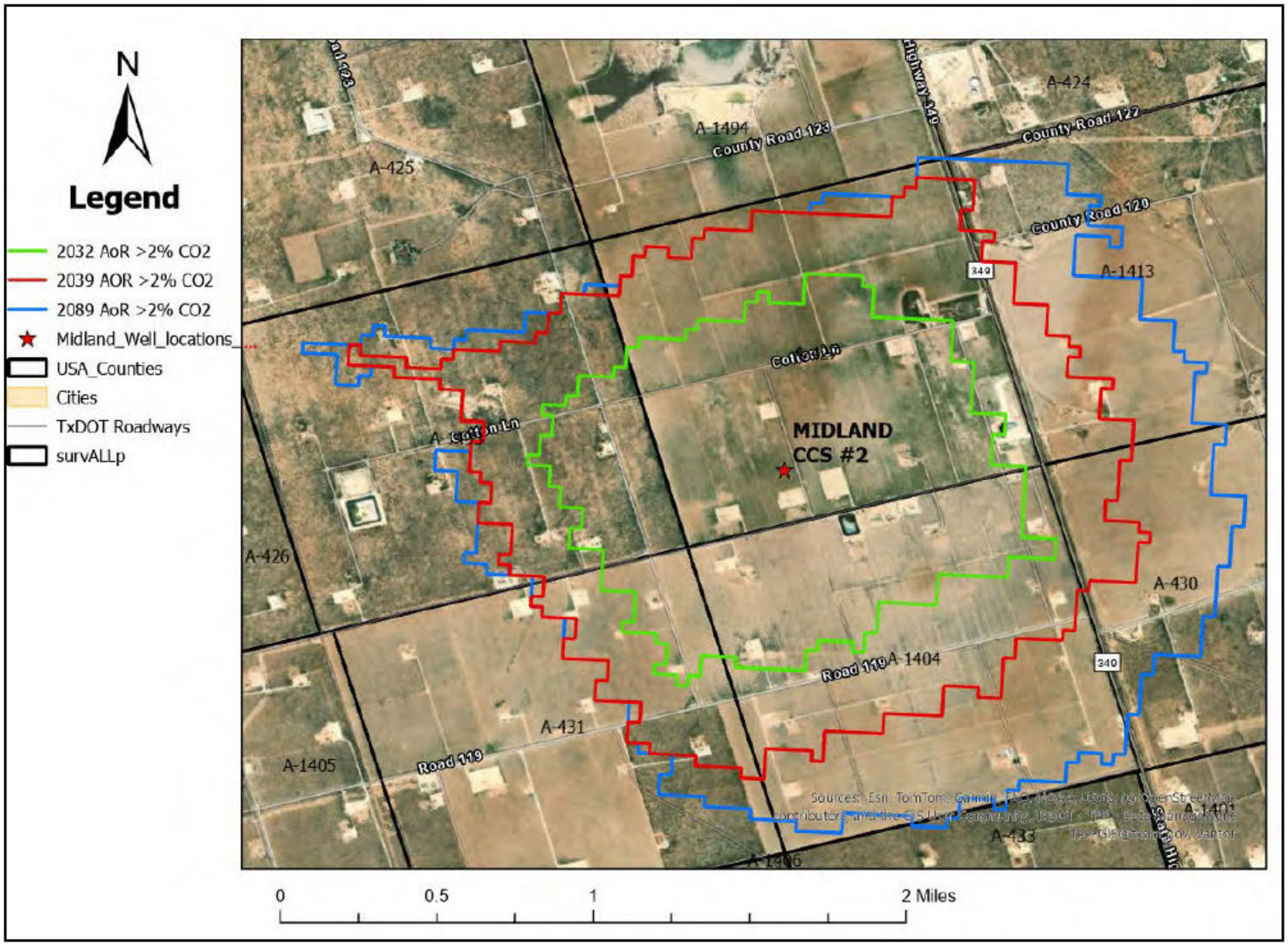


Figure 2-55: Plume Dimensions, (GREEN) 2032 - 5 years after injection; (RED) 2039 - at end of Injection; (BLUE) 2089 - at end of PISC period

Table 2-27: Radius and Area of AoR at Each Model Year

AoR Year	AoR Average Radius (ft)	AoR Area (ft^2)	AoR Area (Acres)
2032	3,192.95	32,028,246.01	735.27
2039	4,594.86	66,327,705.43	1,522.67
2089	5,423.89	92,421,218.76	2,121.70

The following figures from **Figure 2-56** to **2-58** show the pressure at the top of the injection interval (top of Devonian) at the time steps for 5 years after injection, end of injection and end of PISC period.

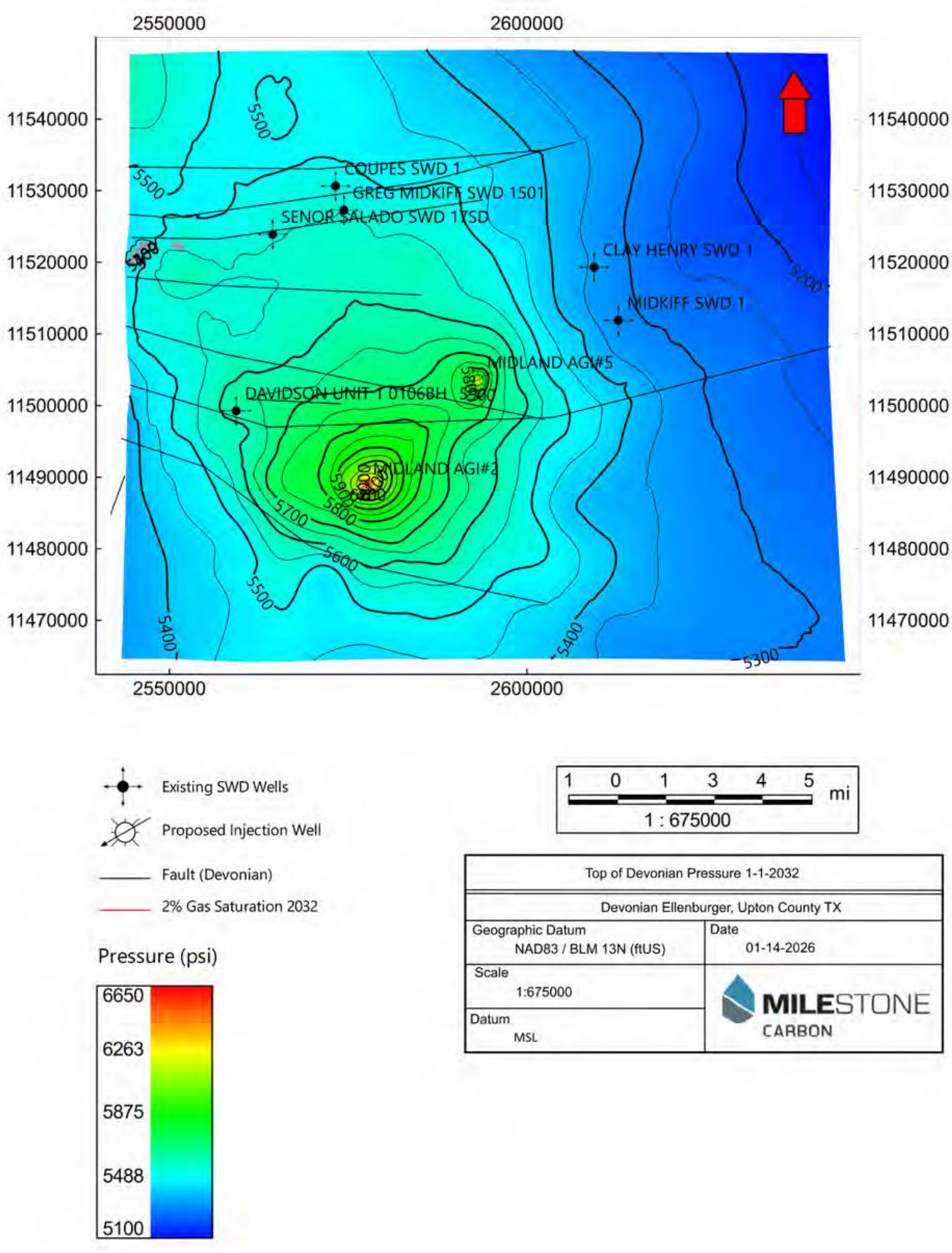


Figure 2-56: Pressure at the Top of Devonian, in PSI, Year 2032, 5 years after Injection Commences

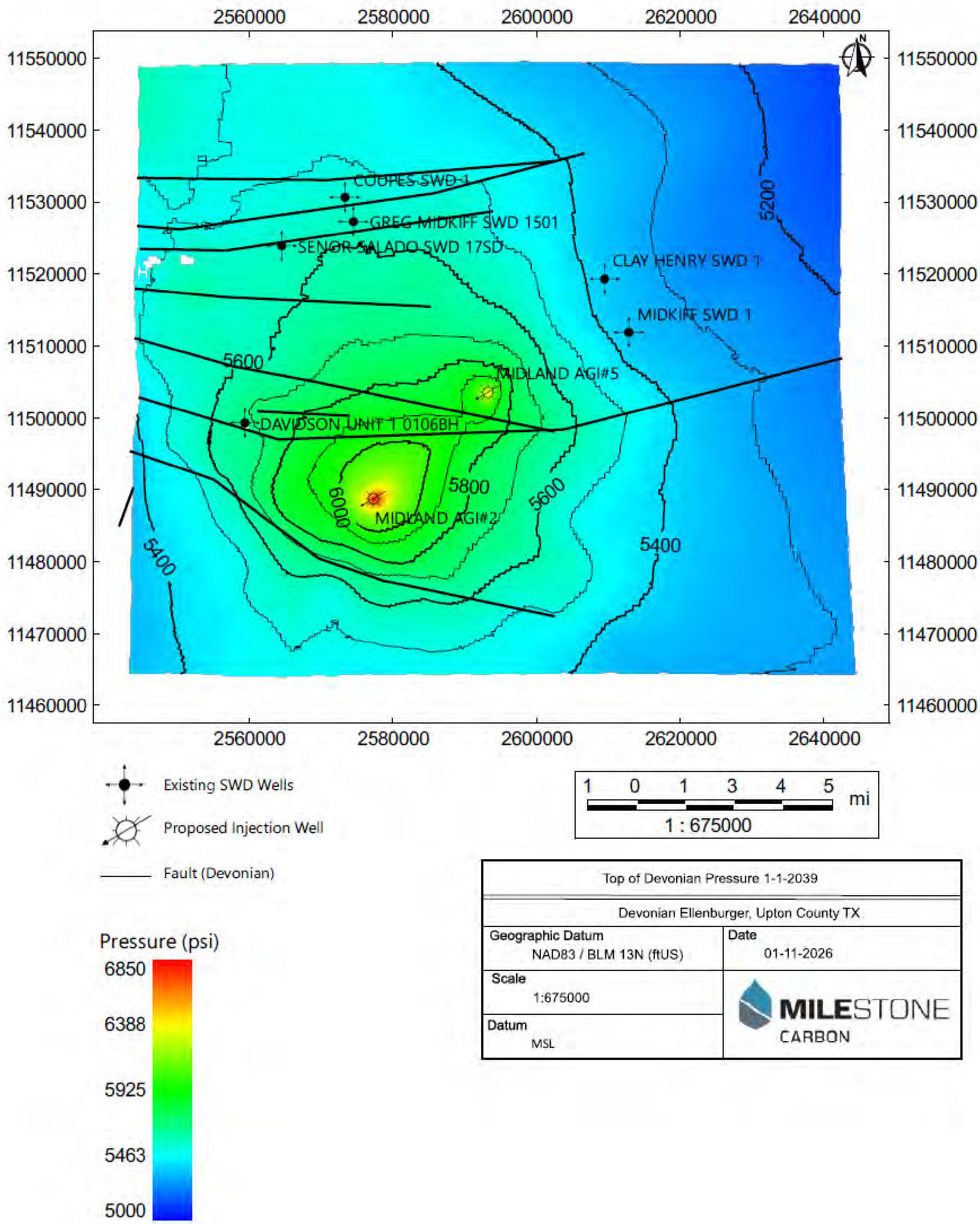


Figure 2-57: Pressure at the Top of Devonian, in PSI, Year 2039, End of Injection Period

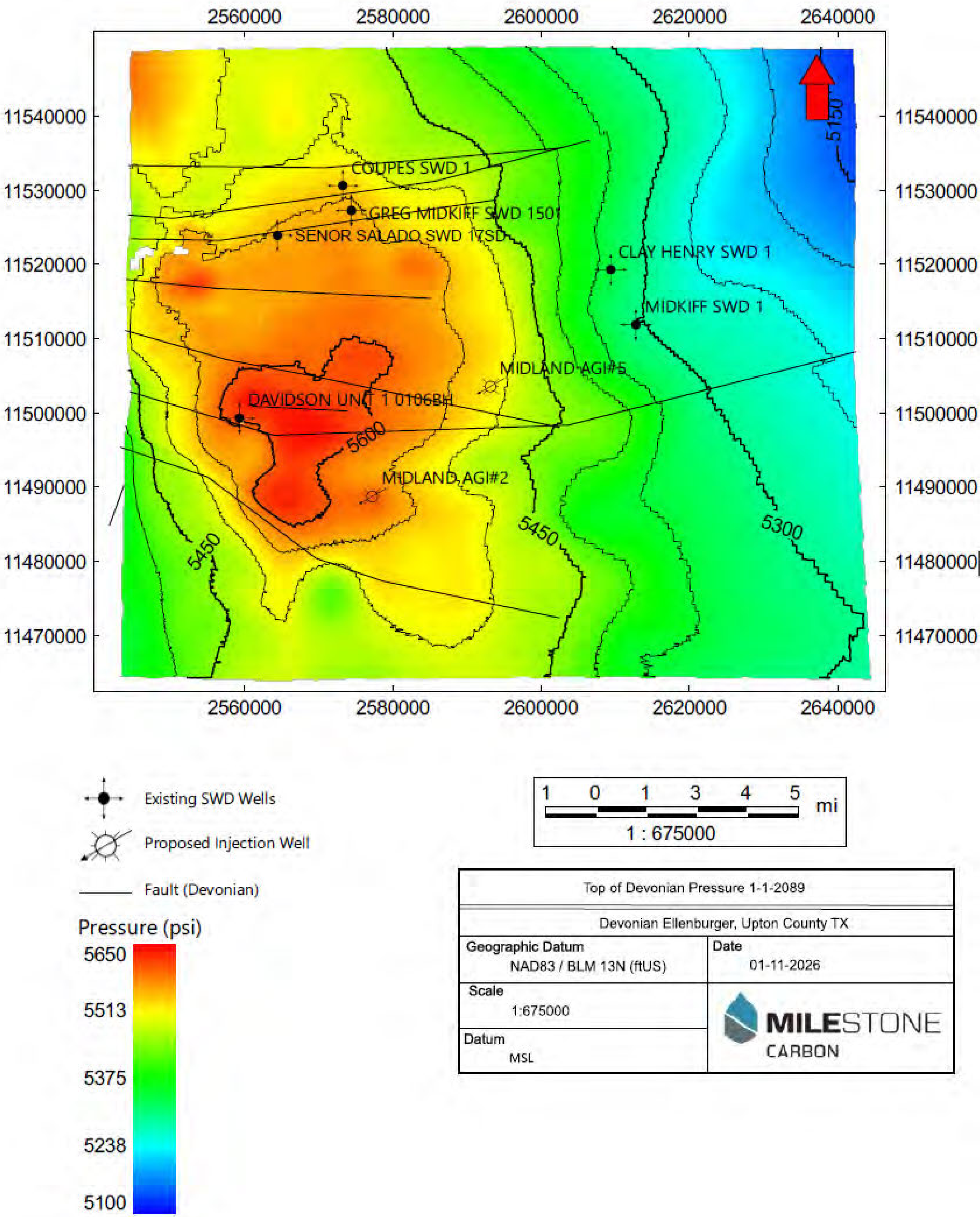


Figure 2-58: Pressure at the Top of Devonian, in PSI, Year 2089, End of PISC Period

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment B: Construction Details / Engineering Design

[40 CFR §146.82, §146.86, §146.87]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Reviewed by

Octane Energy

310 W Wall St., Suite 300

Midland, Texas 79701

Updated 14 January 2026

Table of Contents

List of Tables

List of Figures

3.0 CONSTRUCTION DETAILS / ENGINEERING DESIGN [40 CFR 146.82(a)(7), (a)(8), (10), (11), (12) 146.86, 146.87]

Milestone's permit **Section 3** describes the engineering design details, and permit **Section 4** includes operational strategies employed during the planning of the proposed Midland CCS #2 Injection Well which will be completed at a total depth (TD) of ~13,849 ft TVD. This section also features the design and construction of the planned monitoring wells that will be drilled to support injection into the proposed injection wells. Milestone plans to drill one in-zone monitor well, the Midland IZM #2, and one USDW monitoring well, the Midland USDW #1. The Midland IZM #2 will be completed at ~13,785 ft TD TVD in the Devonian and Ellenburger formations. The USDW monitoring well will be completed at ~1,300 ft in the base of the USDW and/or the first permeable zone above 1,250 ft. Additionally, Milestone plans to drill five (5) near surface seismic monitoring and water wells (NSSW), Midland NSSW #1-5. These wells will be completed at ~300 ft each in the Edwards-Trinity (Plateau) aquifer.

3.1 Engineering Design [40 CFR 146.82(a)(11), (12), 146.86]

The design of the injection wells is optimized to permanently sequester CO_2, prevent the movement of CO_2 and subsurface fluids into USDWs, and account for various operational factors, such as injection volume, rate, chemical composition, metallurgical evaluations, physical properties of the injectate fluid, and the corrosive nature of the injectate fluid and its impact on wellbore components. The operation of the wells will be managed to ensure efficient use of pore space in the reservoir and to contain the CO_2 within the authorized injection unit both during and post-injection.

The Midland CCS #2 well and Midland IZM #2 are designed to withstand the corrosiveness of the injectate. Special metallurgies, such as 22CR/25CR, and coatings will be used for the casing, tubing, wellhead equipment, and downhole tools. Additionally, the wellbore cement design and products used to cement the well are designed to create good, reliable bonding between the casing and formations while withstanding the corrosive nature of the injectate. The casings are designed with a sufficient cement sheath to protect the wellbore from developing any channeling out of the injection interval and to maintain the CO_2 below the Top Seal (Woodford Shale).

The wellbore will be designed with production casing including the following tubulars: 7-5/8-in P-110 casing with premium connections from surface to ~500 ft above the Top Seal, the Woodford, a galvanic 7-5/8-in P-110 x 7-5/8-in 22CR/25CR crossover, 7-5/8-in 22CR/25CR casing with premium connections from the crossover to ~60 ft into the top of the injection interval, the Devonian, and finally openhole to TD, ~100 ft above basement (see permit **Section 1** for stratigraphic column). **Figure 3-1** illustrates the proposed injection wellbore schematic.

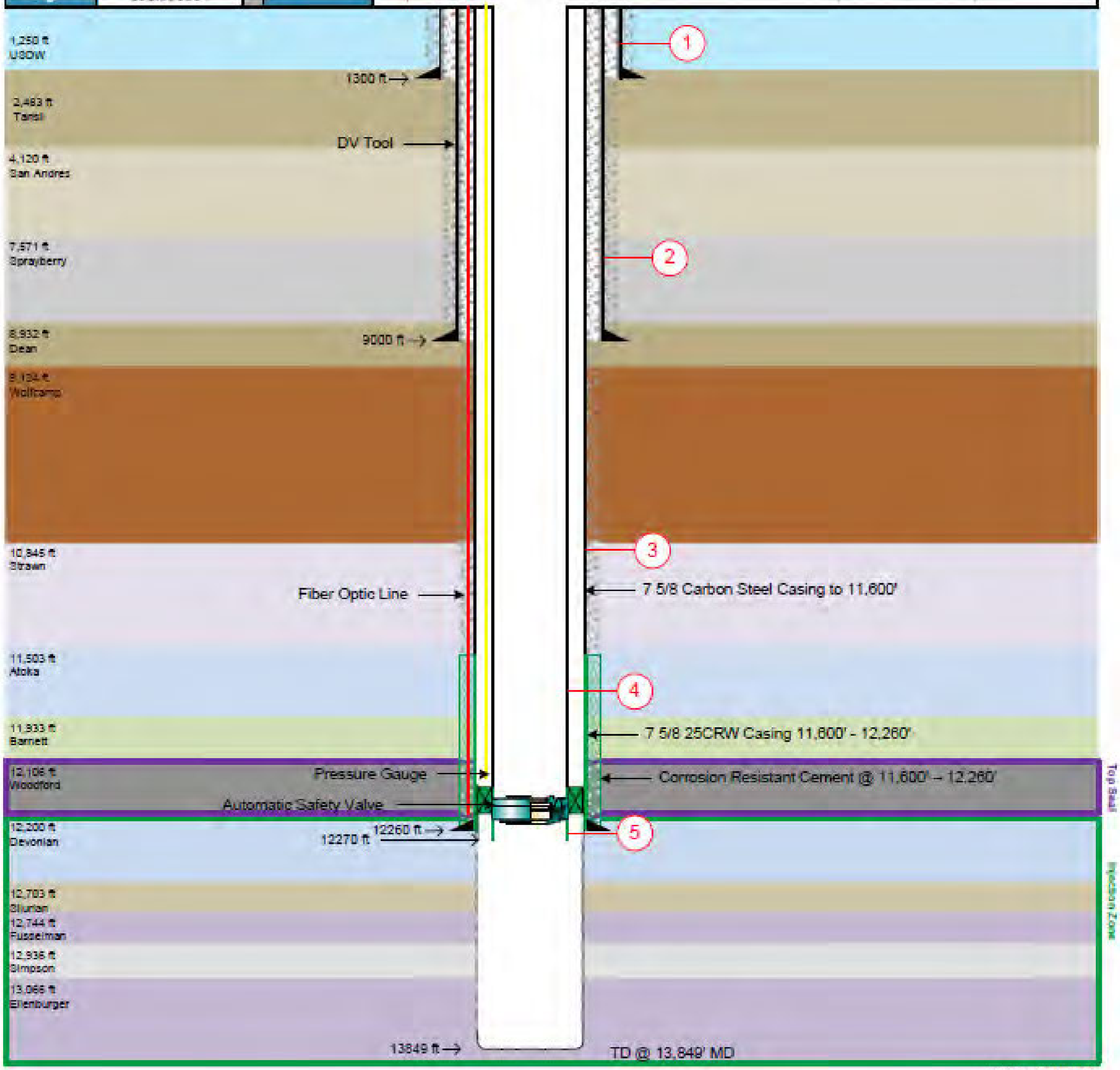
The production tubing will be 4-½-in P-110 with premium connections installed from surface to 162 ft above the production casing shoe set into an upper sealbore assembly just above a 4-½-in x 7-5/8-in fixed permanent production packer. The upper sealbore will allow the 4-½" tubing to be retrieved without pulling the packer. The packer should be located approximately +/-150 ft above the production casing shoe provided there is at least 60% good cement bonding across the isolating shale directly above the top of the injection interval. The production packer will be made of 22CR/25CR or equivalent material. Included below the packer assembly will be a 4-½-in safety valve, 4-½-in blast joint, and a wireline re-entry guide all made of 22CR/25CR or equivalent material extending beyond the production casing shoe. The 4-½-in safety valve made of 22CR/25CR, or equivalent material.

The tubing and casing annulus pressures will be continuously monitored to ensure that well integrity is maintained. The SCADA system will measure and record downhole temperatures and pressures in the injection interval and assist in monitoring the CO_2 plume's size. The monitoring system includes running a fiber optic cable (red line on **Figure 3-1**) and tubing encapsulated conductor (pressure gauge / yellow line on **Figure 3-1**) with downhole pressure gauges as the production casing is run in the hole. The cable and sensors will then be cemented into place. See permit **Section 6** for additional information regarding monitoring plan.

Well Name:	Midland CCS #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,800'
Depth (TVD):	13,849'
Texas Central NAD 83	
Location X:	1780908.86
Location Y:	10555246.59
Lattitude:	31.615788°
Longitude:	-101.990004°

Casing Program

#		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	10 3/4	51	P110HC	BTC	9.85	12 1/4	0	9,000	0
3	Production:	7 5/8	39	P110EC	VAM 21	6.625	9 1/2	0	11,600	0
				25CRW	SFJ			11,600	12,260	11,600
4	Injection Tbg:	4 1/2	15.1	P-110	SLIJ-II	3.826		0	12,098	
5		4 1/2	15.1	25CRW	SFJ	3.826	6 1/8	12,098	12,270	



Printed 8/8/25

Figure 3-1: Proposed Midland CCS#2 Wellbore Schematic

The proposed wellbore schematic illustrates geologic formation tops, including the upper confining zone (Top Seal) and injection intervals and units, well construction elements to best suit the storage of CO_2, such as CRA materials, and proposed monitoring equipment.

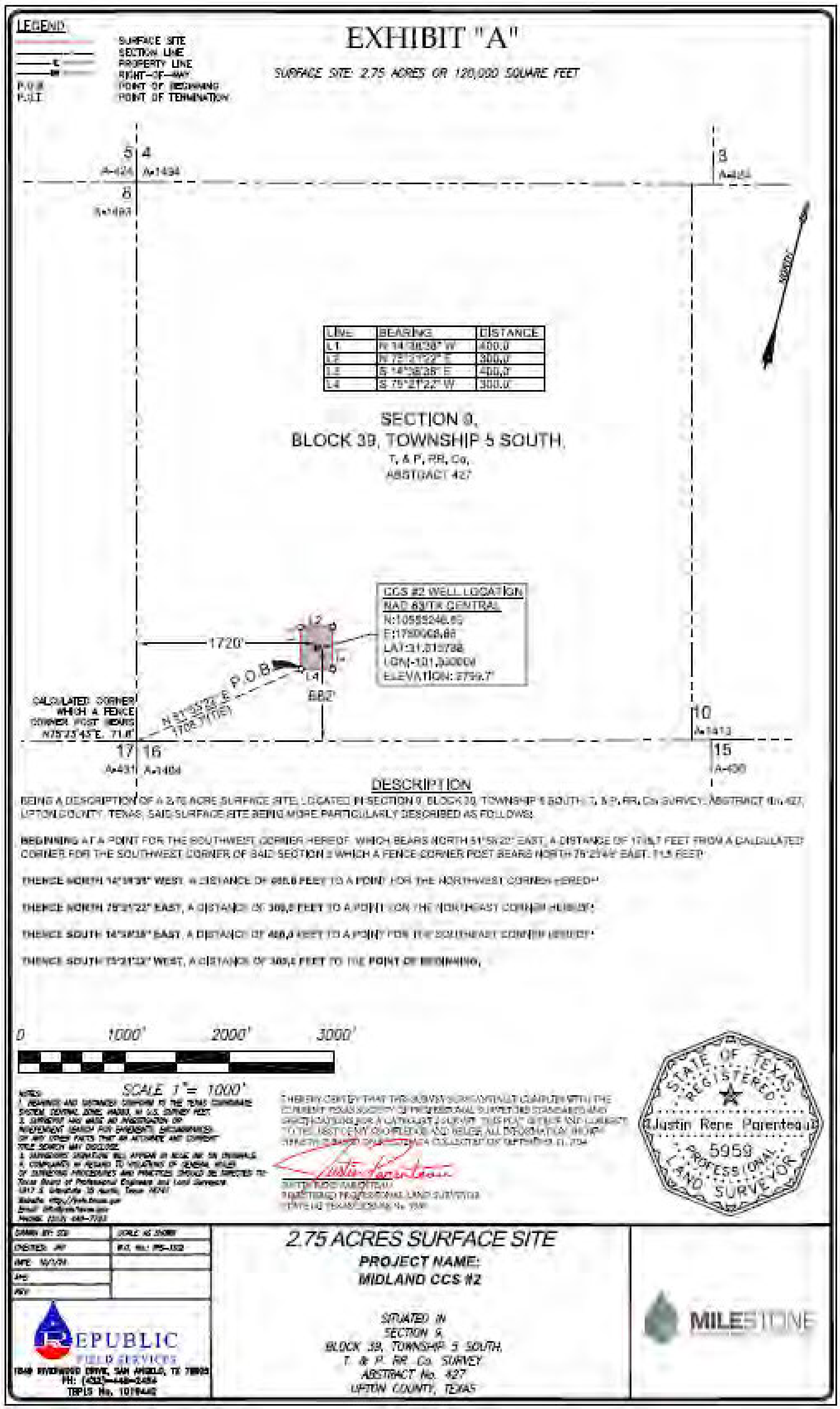


Figure 3-2: Well Location Plat CCS#2

The surveyed well location plat shows the proposed Midland CCS #2 Well location in Section 9, Block 39, Township 5 South, Abstract No. 427, T&P RR Co. Survey, Upton County, Texas.

3.2 General Outline of Injection Well Design and Completion Schematic

The Midland CCS #2 Well is designed with the following specifications:

1. Conductor Pipe
    a. Size: 20 inches (in)
    b. Depth: 120 ft (ft)
2. Surface Casing
    a. To be set below the lowermost Underground Source of Drinking Water (USDW)
        i. Currently estimated: 1,250 ft
            1. Based on offset GAU Determination letters **(Appendix I)** issued by the RRC.
        ii. USDW depth and location will be further confirmed via openhole logging during drilling of the well
    b. 13-3/8-in casing set at ~1,300 ft
    c. J-55 grade tubulars
    d. 17-½-in hole size
    e. Cement to surface
3. Intermediate Casing
    a. 10-3/4-in casing set into top of Dean @ ~9,000 ft
    b. P110HC grade tubulars
    c. 12-¼-in hole size
    d. Cement to surface
        i. DV Tool set at ~4,100 ft
4. Production Casing
    a. 7-5/8-in casing set into top of Devonian @ ~12,260 ft
        i. P-110EC grade tubulars from surface to 11,600 ft
        ii. Galvanic crossover (X-O) between P-110EC & 22CR/25CR
        iii. 22CR/25CR, 110 ksi grade tubulars from 11,600 ft to 12,260 ft
        iv. 9-½-in hole size
    b. Cement to surface
        i. Cement to be comprised of the following make-up:
            1. From surface to ~500 ft above the top seal – (light weight acid resistant cement)
            2. From ~500 ft above the top seal, throughout the injection interval, to shoe – (acid resistant cement)
5. Injection Tubing
    a. 4-½-in tubing set on packer at 12,270 ft
        i. Tubing P-110 grade
        ii. Packer 22CR/25CR or equivalent
        iii. Coated with H2S and CO2 resistant coating
    b. Subsurface Tejas InjectGARD Variable Orifice Safety Valve at ~12,262 ft
        i. 22CR/25CR or equivalent
        ii. API-14A, V3 rated
        iii. Wireline retrievable
    c. 4-½-in blast joint and re-entry guide to 12,270 ft
    d. Annular fluid to consist of corrosion inhibited fluid
6. Packer Configuration
    a. 4-½-in x 7-5/8-in permanent packer set at 12,098 ft
        i. 22CR/25CR or equivalent, Inconel-lined (flow-wetted) anchor, mandrel, and cylinder for corrosion resistance
            1. Minimum ID: 3.875-in
            2. Elastomer options – Nitrile, HNBR, Aflas (CO_2 resistant)
7. Wellhead
    a. 13-3/8-in SOW x 13-5/8-in 5M – conventional casing head
    b. 13-5/8-in 10-3/4-in – casing hanger
    c. 13-5/8-in 5M x 13-5/8-in 10M – casing spool
    d. 13-5/8-in 7-5/8-in – casing hanger
    e. 13-5/8-in 10M x 13-5/8-in 10M DSA for Fiber Optic Line Exit
    f. 13-5/8-in 10M x 11-in 10M – tubing spool
    g. 11-in 10M x 2-9/16-in 10M Temporary Abandonment Cap + Valve with 11-in isolation busing assembly for vertical dual barrier isolation
8. Completion Injection Tree
    a. 11-in x 4-½-in – tubing hanger (FF1.5 trim, 410 Stainless Steel)
9. Production Tree
    a. 11-in x 4-1/16-in 10M – adapter spool (EE trim, Xylan Coated Internally)
    b. 4-1/16-in 10M, gate valve, manual (FF trim)
    c. 4-1/16-in 10M, gate valve, manual (EE trim, Xylan Coated Internally)
    d. 4-1/16-in X 5-1/8-in 10M flow cross with 4-1/16-in 10M pneumatic wing valve (EE trim, Xylan Coated Internally)
    e. 4-1/16-in 10M, gate valve, manual for crown with cap (EE trim, Xylan Coated Internally)
    f. See schematic for details (**Figure 3-7**)

A complete drilling and completion prognosis has been included in **Section 13 Appendix B**.

3.3 Detailed Discussion of Injection Well Design

The Facility is designed to inject a volume of 1.0 MMT/yr of CO_2 which translates to a yearly injection rate of approximately 54.5 million standard cubic ft per day (MMscf/d) at standard conditions. The source of the injectate will be gas processing facilities in the Midland Basin or Direct Air Capture facilities. **Table 3-1** shows the standard conditions of CO_2 which are used in the modeling and flow calculations.

Table 3-1: CO_2 Standard Conditions

CO_2 Mixture Standard Conditions				
Temperature deg-F	Pressure Psia	Density lbm/cuft	Z-Factor	Molecular Weight g/mol
60	14.696	0.1134	0.9942	42.786

An analysis was conducted on the tubing design utilizing various factors such as pipe friction losses, exit velocities, compression requirements, and economic evaluations. Using the results of a detailed nodal analysis, the tubing head injection pressure was determined. Simulation surface pressure outputs were used to identify the point during the project's lifespan when the maximum flowing pressure at the surface occurs. This information is used to properly design the casing, tubing, and wellhead configurations. The nodal analysis inflection point of both plots shows that a 4-½-in tubing was determined to be the appropriate tubing size necessary to move the desired volumes of supercritical CO_2 in this well based on the results from the model. The results also show that ~60 MMSCF/d is the maximum rate the 4-½" tubing can sustain without significant frictional losses.

The composition specifications for the CO_2 stream to be injected in Well are presented in **Table 3-2**. A specification is provided for maximum and minimum values of the gas stream as it may vary over the life of injection. Milestone will monitor the gas stream over time. See permit **Section 6** for information about injectate stream monitoring. For the purposes of modeling a gas composition consisting of 95% CO_2 was utilized.

Table 3-2: CO_2 Stream Composition Specifications

Composition	Composition Max/Min		Composition Used in Modeling Mole %
CO_2	>=	95 mol%	95.0%
Water	<	30 lb/MMscf	
H_2S	<	200 ppmv	0.02%
N_2	<	4 mol%	1.0%
Sulfur	<	35 ppmv	
O_2	<	10 ppmv	
Hydrocarbon	<	5 mol%	3.555% CH_4
Glycol	<	.3 gal/MMscf	
CO	<	4,250 mg/kg	0.425%
NOx	<	1 mg/kg	
SOx	<	1 mg/kg	
Particulates	<	1 mg/kg	
Amines	<	1 mg/kg	
H_2	<	1 mol%	
Hg	<	5 ng/l	
NH_3	<	50 mg/kg	
Ar	<	1 vol%	
Comp. Lube Oil	<	50 mg/kg	

Table 3-3 shows the calculated injection parameters from the tubing size evaluation based on the inputs described in **Table 3-1**:

Table 3-3: Calculated Injection Parameters

Location	Pressure PSI	Temperature deg-F	Density lb/ft3	Phase
Pipeline Take Point	3,100	60	57.6	Liquid
Wellhead Surface Pressure	2,949	60	57.4	Liquid
Well Midpoint Midland CCS #2	5,149	131	53.2	Supercritical
Bottomhole Conditions Midland CCS #2, Midpoint Siluro-Devonian Injection Unit	6,741	188	50.8	Supercritical
Bottomhole Conditions Midland CCS #2, Midpoint Ellenburger Injection Unit	7,101	199	50.7	Supercritical

A 4-½-in tubing was determined to be the appropriate tubing size necessary to move the desired volumes of supercritical CO_2 in this well based on the results from the nodal analysis model. The model also verified that the CO_2 would remain in supercritical state (**Figure 3-3**) in the wellbore. The CO_2 is in a liquid state when it enters the wellbore but converts to supercritical state once the critical temperature is reached at approximately 2,000 feet below surface and continues to stay supercritical throughout the path of the wellbore as it is being injected. The change from liquid to supercritical has minimal changes in density and viscosity which are accounted for in the model.

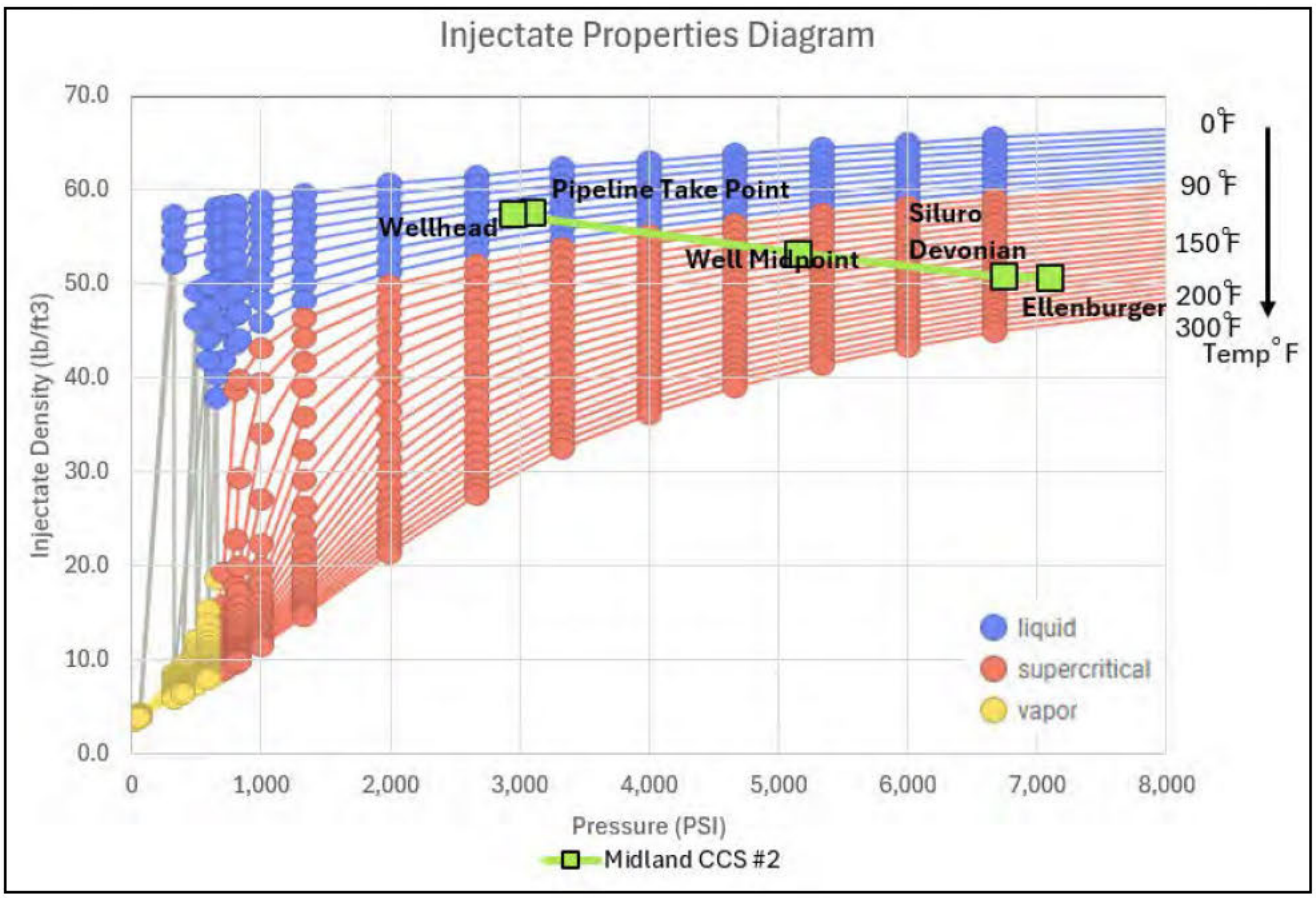


Figure 3-3: CO_2 Flow Conditions

3.3.1 Casing Summary

The Midland CCS #2 Well will use the following casing sizes and lengths (**Table 3-4**):

- 20-in conductor pipe drilled to 120 ft
- 17-½-in openhole with 13-3/8-in surface casing drilled to 1,300 ft
- 12-¼-in openhole with 10-¾-in intermediate casing drilled to 9,000 ft
- 9-½-in openhole with 7-5/8-in production casing drilled to 12,260 ft
- 6-1/8-in openhole drilled to 13,849 ft

Table 3-4: Casing Summary (CCS #2)

Casing String	Set Depth (ft)	Borehole Diameter (in)	Wall Thickness (in)	Outer Diameter (in)	Casing Weight (lb/ft)	String Weight (lbs)
Conductor (X-42, Welded)	120	20.000	0.750	20.000	78.6	9,432
Surface (J55, BTC)	1,300	17.500	0.760	13.375	54.5	70,850
Intermediate (P110HC, BTC)	9,000	12.250	0.450	10.750	51.0	459,000
Production (P110EC/25CRW, VAM 21/SFJ)	12,260	9.500	0.500	7.625	39.0	478,140

3.3.2 Conductor Pipe

Due to the loose and unconsolidated nature of the sediments found near the surface, a 20-in conductor pipe will be required down to a depth of 120 ft to maintain the integrity of the hole during initial drilling of the Well. This will be the outermost casing string. Tubular specifications for the conductor pipe are summarized and presented in **Table 3-5**:

Table 3-5: Conductor Pipe Specifications (CCS #2)

Conductor Pipe								
Description	Casing Wt. (lb/ft)	Depth (ft)	Tensile (psi)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in)	Drift ID (in.)
20", 78.6#, X-42, Welded	78.6	120	971,000	320	1,380	0.36	19.25	NA

3.3.3 Surface Casing

The surface casing section of the Well will be drilled and completed using 13-3/8-in casing, which will create enough annular space to securely cement the casing to surface. The surface hole will be drilled with casing set at 1,300 ft which exceeds the RRC minimum required depth of 100 ft below USDW measured from ground level. This casing string will provide two (2) barriers to prevent contamination of USDW during drilling operations. A cement bond logging tool will be used to evaluate the quality of cement bond and ensure surface casing was successfully set.

Tubular specifications for the surface casing are presented in **Tables 3-6: A** through **D.**

Table 3-6: A through D: Surface Casing Specifications (CCS #2)

A: Surface Casing

Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
13-3/8", 54.5#, J55, BTC	54.5	1,300	853	1,130	2,740	0.1546	12.615	12.459

B: Annular Geometry

Section	ID	MD	TVD
	(in)	(ft)	(ft)
Drive Pipe	19.25	120	120
Open Hole	17.5	1,300	1,300

C: Casing

Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Surface	13.375	12.615	54.5	1,300	1,300

D: Cement

System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Lead	0	1,000	1,347
Tail	1,000	1,300	452

Table 3-7: Surface Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Drive Pipe/Casing Annulus Lead Cement	120	1.0454	0%	125
Openhole/Casing Annulus Lead Cement	880	0.6946	100%	1,222
Openhole/Casing Annulus Tail Cement	300	0.6946	100%	417
Shoe Track	40	0.8680	0%	35

To ensure cement returns to surface are achieved, 100% excess of openhole volumes were used.

3.3.4 Intermediate Casing

The intermediate casing section will be drilled and completed using 10-¾-in casing to provide sufficient annular space to securely cement the casing to surface. This casing string alone will provide an additional two (2) barriers to USDW during drilling operations. After the surface and intermediate casing are set, there will be four (4) barriers between the USDW and fluid in the wellbore. A cement bond logging tool will be used to evaluate the quality of cement bond and ensure intermediate casing was successfully set.

Tubular specifications for the intermediate casing are presented in **Tables 3-8** and **3-9.**

Table 3-8: A through D: Intermediate Casing Specifications (CCS #2)

A: Intermediate Casing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
10-¾-in, 51#, P110HC, BTC	51.0	9,000	1,820	4,900	9,420	0.0943	9.850	9.694

B: Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Surface Casing	12.615	1,300	1,300
Openhole	12.25	9,000	9,000

C: Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Intermediate	10.750	9.850	51.0	9,000	9,000

D: Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Stage 2	0	4,500	1,092
Stage 1	4,500	9,000	1,149

Table 3-9: Intermediate Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Stage 2 Intermediate Casing/Casing Annulus Lead Cmt	1,300	0.2377	0%	309
Stage 2 Openhole/ 10-¾-in Casing Annulus Lead Cmt	2,700	0.1882	30%	661
Stage 2 Openhole/ 10-¾-in Casing Annulus Tail Cmt	500	0.1882	30%	122
Stage 1 Openhole/ 10-¾-in Casing Annulus Lead Cmt	4,000	0.1882	30%	979
Stage 1 Openhole/ 10-¾-in Casing Annulus Tail Cmt	500	0.1882	30%	122
Shoe Track	90	0.5292	0%	48

To ensure cement returns to surface are achieved, 30% excess of openhole volumes were used.

3.3.5 Production Casing

Production casing (long-string casing) runs from surface into the injection interval at 12,260 ft and is cemented to surface. After the surface, intermediate and production casing are set, there will be six (6) barriers between USDW and fluid in the wellbore. Design criteria of production casing include P-110EC material, 22CR/25CR material, acid resistant cement, and downhole tools such as centralizers, float equipment, galvanic crossover (X-O), and fiber optic cable (FOC).

A comprehensive metallurgical analysis, which considered the chemical composition of the CO_2 injectate and downhole conditions, was conducted and is included in **Section 13 Appendix A**. The analysis determined that the CO_2 injectate is not corrosive on its own. However, to protect against the potential of water from the reservoir entering the wellbore, and to guard against potential corrosion issues or failures, a subsurface safety valve will be installed just below the packer isolating the tubulars above. The safety valve and all tubulars below it will include 22CR/25CR material which was determined to be the appropriate metallurgy for downhole tubulars that will contact the injectate stream and reservoir fluids.

Acid resistant cement (**Section 3.3.11**) will be used to protect the cement sheath from degradation due to exposure to an acidic environment, thereby improving wellbore integrity and extending the lifespan of the well. As illustrated in **Figure 3-1**, corrosion resistant cement will be placed from approximately 500 ft above the top of the Top Seal, across the injection interval, to casing shoe. The entire cement column will be circulated to surface using a single-stage cement job.

Finally, an FOC will be installed with the production casing and cemented into place. The FOC will be used to record downhole temperatures in the injection intervals and tied into a SCADA system at surface.

To facilitate long-term monitoring, after plugging, the openhole section in abandoned injection intervals will remain open, below corrosion-resistant bridge plugs, for continuous monitoring of reservoir temperature and pressure. However, the lifetime of FOC is debatable and may not extend beyond 20 years. Milestone will follow all manufacturer guidelines and best practices regarding FOC installation and maintenance to extend the life of the FOC.

The wellbore will be designed with production casing including the following tubulars. 7-5/8-in P-110EC casing with premium connections from surface to 11,600 ft, a galvanic 7-5/8-in P-110 x 7-5/8-in 22CR/25CR crossover at 11,600 ft, and 7-5/8-in 22CR/25CR casing with premium connections from 11,600 ft to 12,260 ft. **Figure 3-1** illustrates the proposed wellbore schematic. Tubular specifications for the production casing are presented in **Tables 3-10** and **3-11**:

Table 3-10: A through D: Production Casing Specifications (CCS #2)

A: Production Casing								
Description	Casing Wt. (lb/ft)	Length (ft)	Tensile (1k lbs)	Collapse (psi)	Burst (psi)	Capacity (bbl/ft)	ID (in.)	Drift ID (in.)
7-5/8-in, 39#, P-110EC, VAM 21	39.0	11,600	1,399	12,180	14,340	0.0426	6.625	6.500
7-5/8-in, 39#, 22CR/25CR-110, SFJ	39.0	660	1,399	12,180	14,340	0.0426	6.625	6.500

B: Annular Geometry			
Section	ID	MD	TVD
	(in)	(ft)	(ft)
Intermediate Casing	9.850	9,000	9,000
Openhole	9.50	12,260	12,260

C: Casing					
Section	OD	ID	Weight	MD	TVD
	(in)	(in)	(lb/ft)	(ft)	(ft)
Production	7.625	6.625	39.0	12,260	12,260

D: Cement			
System	Top	Bottom	Volume of Cement
	(ft)	(ft)	(CF)
Lead	0	11,900	2,501
Tail	11,600	12,260	172

Table 3-11: Production Casing Cement Calculations (CCS #2)

Volume Calculations				
Section	Footage	Capacity	% Excess	Cement Volume
	(ft)	(cf/ft)	(%)	(cf)
Production Casing/Intermediate Casing Annulus Lead Cement	9000	0.2121	0%	1,909
Production Openhole/7-5/8" x 9-½" Casing Annulus Lead Cement	2600	0.1751	30%	592
Production Openhole/7-5/8" x 9-½" Casing Annulus Tail Cement	660	0.1751	30%	150
Shoe Track	90	0.2394	0%	22

To ensure cement returns to surface are achieved, 30% excess of openhole volumes were used. The production casing will be installed using premium connections.

3.3.6 Centralizers

Centralizer selection and installation for the referenced well will have two (2) separate functions. The bow-spring centralizer design for the 13-3/8-in surface casing will be planned to protect any shallow aquifer zones per state regulations. The specific placement is also to ensure a continuous, uniform, column of cement is present throughout the 1,300 ft of 13-3/8-in x 17-½-in annular space. The recommended locations are:

(1) – Above Shoe Joint
(1) – Above Float Collar
(1) – Subsequent (5) joints of casing
(1) – Every 4th joint (160 ft) to surface
Total Centralizers – 13

The bow spring centralizer design for the 10-¾-in intermediate casing will be planned to ensure a continuous, uniform, column of cement is present throughout the 9,000 ft of 10-¾-in x 12- ¼-in annular space. The recommended locations are:

(1) – Above Shoe Joint
(1) – Above Float Collar
(1) – Subsequent (5) joints of casing
(1) – Every 4th joint (160 ft) to surface
Total Centralizers – 61

The selection and installation of centralizers for the 7-5/8-in production casing will consider the installation of the FOC. Both clamp centralizers and eccentric centralizers, made from the same material as the production casing, will be used to ensure the FOC are not damaged during the installation process.

1. Utilize two (2) eccentric centralizers (slide on) across a two (2) joint shoe track. Install cable clamp above top eccentric centralizer for cable security.
2. Install clamp centralizers every 160 ft or four (4) joints to surface, cable detection clamps every three (3) to four (4) joints.
3. Fiber module protectors every five (5) to six (6) joints.

3.3.7 Injection Tubing

As previously stated, the size of the injection tubing was chosen based on the injection volume, rate, and injectate composition. It is important to consider the injectate and the potential for a corrosive environment when selecting the material of the tubing, similar to the casing string. The injectate stream is expected to be dry and non-corrosive, but the design allows for the possibility of the invasion of connate water from the reservoir. A comprehensive summary of the metallurgical analysis is included in **Section 13 Appendix A** of this application. Considering the potential for the presence of carbonic acid in a mixture of water and CO_2, tubing made of 22CR/25CR material or equivalent is recommended below the safety valve. Since the safety valve will be closed any time injection is stopped, there will be no connate water from the reservoir above the safety valve and P-110 tubulars will be utilized above. Injection tubing specifications are presented in **Table 3-12**. Coatings also discussed below.

The tubing and production casing annulus will be filled with a corrosion inhibited fluid as approved by UIC Program Director, prior to setting the packer. The annular fluid will contain brine made up with CaCl, an oxygen scavenger, a corrosion inhibitor, and a biocide. Milestone may add additional chemicals to the annular fluid based on recommendations of vendors. The technology in this area is evolving rapidly and Milestone intends to use best in class annular fluids tailored to our injection wells.

During operation, positive pressure of +100 psi will be maintained and monitored on the annulus (see permit **Section 6.2** for additional notes on annular pressure).

Finally, a Tubing Encapsulated Cable (TEC) will be installed with the injection tubing. The TEC will contain pressure gauges installed just above the packer and will be used to record pressures in the injection stream inside the tubing as well as the annular pressure of the tubing and tied into a SCADA system at surface. The combination of these pressure values will aid in tubing leak detection.

Table 3-12: Injection Tubing Specifications (CCS #2)

Tubing								
Description	**Casing Wt. (lb/ft)**	**Length (ft)**	**Tensile (1k lbs)**	**Collapse (psi)**	**Burst (psi)**	**Capacity (bbl/ft)**	**ID (in.)**	**Drift ID (in.)**
4-½", 15.1#, P-110, SLIJ-II	15.1	12,098	485	14,350	14,420	0.0149	3.826	3.701
4-½", 15.1#, 22CR/25CR-80, SFJ	15.1	172	250	11,090	10,480	0.0149	3.826	3.701

The tubing will be installed using semi-flush joint connections.

The 4.5" diameter, 15.1 lb/ft, P-110 injection tubing with VAM SLIJ-II couplings has sufficient axial strength and meets and/or exceeds the design tension safety factor of 1.4. The tension safety factor was analyzed using Halliburton's WellCat software and was evaluated for expected operating conditions and a worst case scenario using fully evacuated casing (tubing in air) at different overpulls of 0, 25,000, and 50,000 lbs. The axial strengths of the 4.5", 15.1 lb/ft, P-110 pipe body and the 4.5", 15.1 lb/ft, P-110 VAM SLIJ-II connections are 484,818 and 344,000 lbf, respectively. The lower value, corresponding to the strength of the connections, was used in the calculation of the safety factor. An expected maximum axial load of 235,247 lbf, corresponding to the fully evacuated, 50,000 lbf overpull scenario, results in a minimum calculated safety factor of 1.46. The axial load plot is shown in **Figure 3-4**. The Triaxial load plot for the tubulars is shown in **Figure 3-5**.

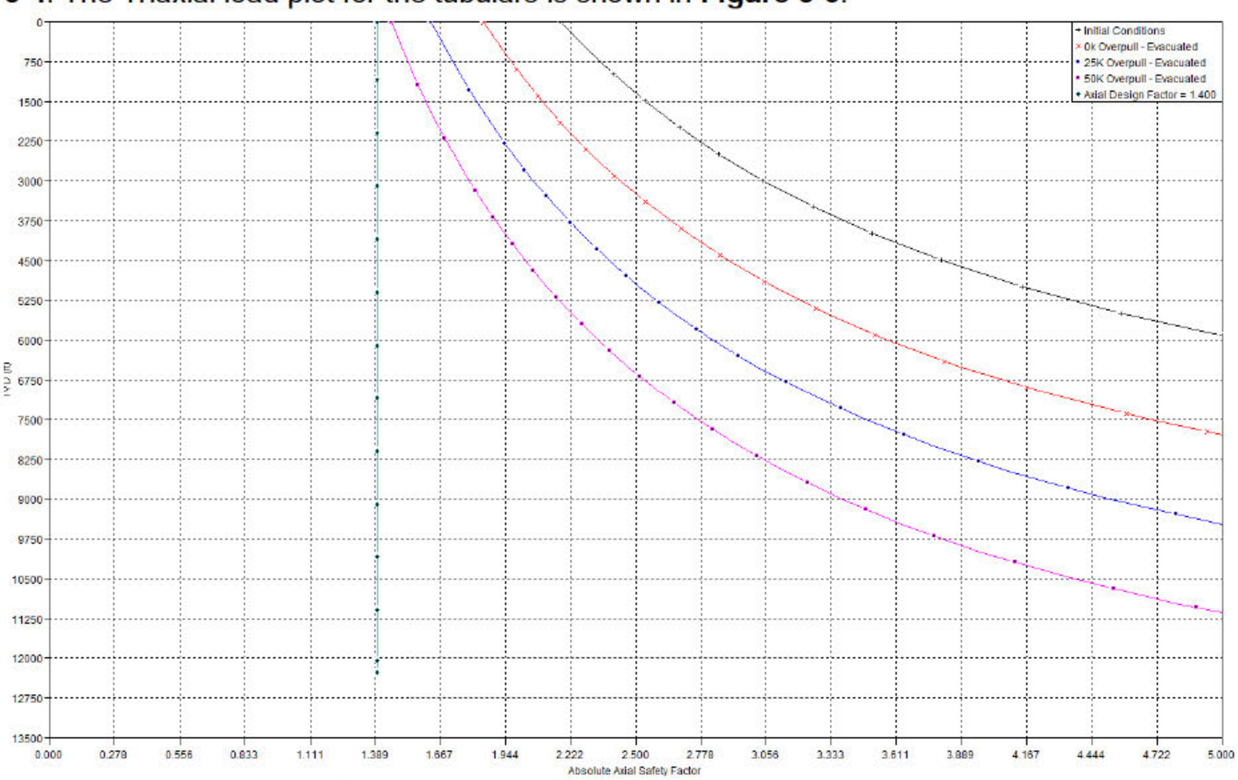


Figure 3-4: Axial Load and Safety Factor vs TVD (FT) for 4.5" Tubing

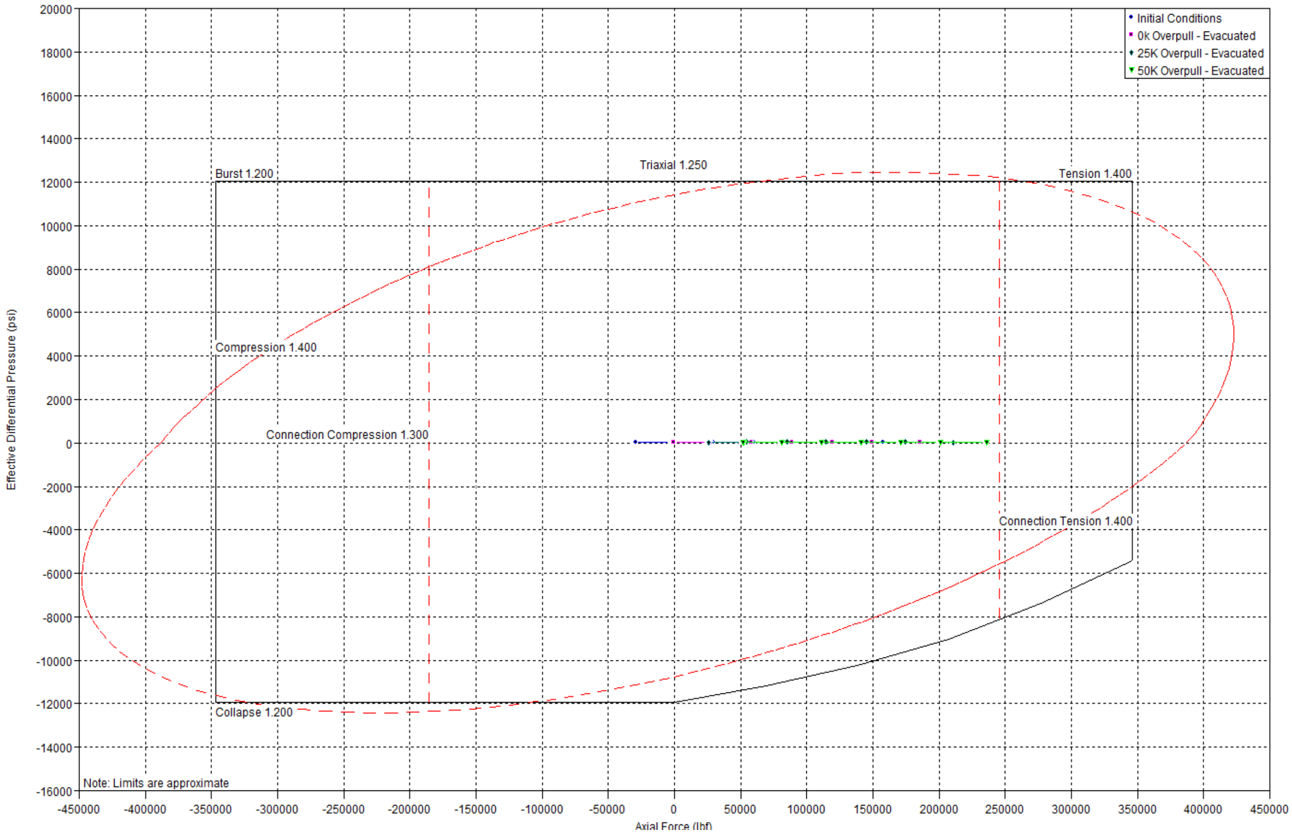


Figure 3-5: Triaxial Load Plot, Axial Load vs Effective Differential Pressure for 4.5" Tubing

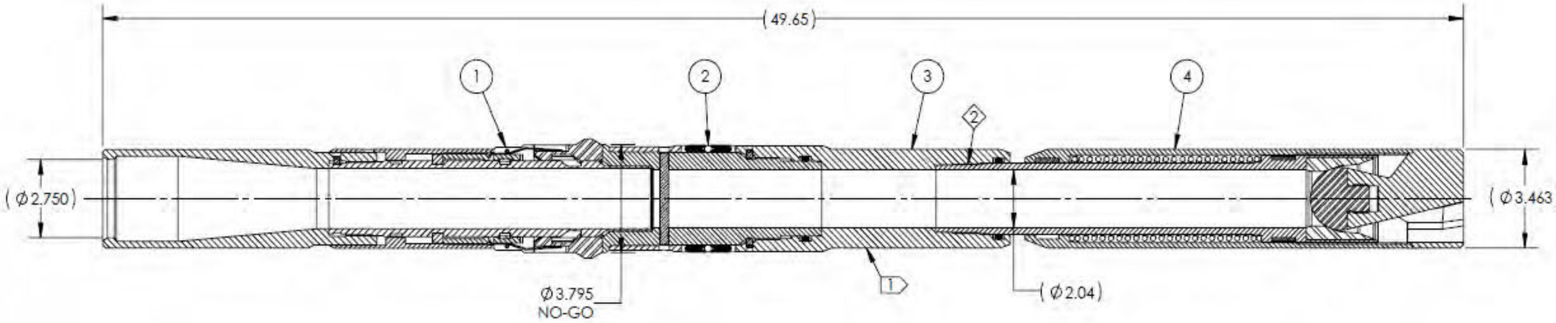
3.3.7.1 Tubular Coatings

Due to the possible presence of low concentrations of H_2S (<200 ppm) and also to mitigate corrosion from any potential CO_2 interactions, Milestone will coat the inside of the P-110 4.5" injection tubing with a H_2S and CO_2 resistant coating. Even though it is unlikely water will be able to migrate above the safety valve, this will form a secondary or backup method of mitigation for corrosion and also protect the tubulars from the low concentrations of H_2S. Milestone will apply a coating that has been proven effective through testing under conditions containing CO_2 and H_2S, consistent with the gas specifications outlined in **Table 3-2**. Milestone is currently evaluating NOV Tuboscope coatings such as TK7, TK15-XT and TK805. Milestone will apprise the UIC director of the final coating selection.

3.3.8 Safety Valve

A safety valve (**Figure 3-6**) will be installed in the 4-½-in tubing near the packer **(Figure 3-1)**. This valve will automatically close when injection is stopped and will aid in the running of logging and recompletion tools when necessary. If logging or recompletion tools need to be run below the valve, the valve can be removed via wireline. The valve is a variable orifice design controlled by flow rate and only opens when there is a positive injection flow rate and a differential pressure above the valve. The valve is validated to API-14L and consists of CRA materials. It has a 10,000-psi pressure rating. Additional engineering drawings and details are included as a supplemental attachment.

REV.	VECN#	DATE	APPROVED
D	01237	10/17/2023	MBJ



DIMENSIONAL AND ENGINEERING DATA	
FLOW AREA	3.27 SQ. IN.
MAX OD	3.800 IN.
OVERALL LENGTH	49.65 IN.
OPERATING DATA	
RATED WORKING PRESSURE (RWP)	10,000 PSI
MAXIMUM INTERMITTENT FLOW RATE (BBL/DAY)	30,000 BBL/DAY
FLOW WETTED MATERIAL	718, 925, TC
RATED TEMPERATURE RANGE	40° - 350°F
RUNNING TOOL ASSEMBLY	018905
PULLING TOOL ASSEMBLY	018927

ITEM NO.	QTY.	DESCRIPTION	TSN-BOM
1	1	4.500 X 3.750 F HiFLO LOCK ASSY	020586
2	1	4.500 X 3.750 HiFLO PACKING ASSEMBLY (FKM)	022277
3	1	4.500 X 3.750 HiFLO InjectGARD SPACER ASSY	022288
4	1	4.500 X 3.500 InjectGARD ASSY	018641

NOTES :

1. ETCH PART PER TSP - QA - 7.55
2. MASK BOTH ENDS OF THE VALVE SPRING CAVITY, GLASS BEAD PEEN THREADS PER TSP-001, AND MOLY-COAT THREADS PRIOR TO REMOVING THE MASKING MATERIAL FOR FINAL ASSEMBLY

Approved for Manufacture

O-RING DETAILS

45° X .01 TYP
0° 5° TYP
32
R.015 TYP

UNLESS OTHERWISE SPECIFIED

TOLERANCE ON:
X . X ± 0.1 [2.5]
X . XX ± 0.01 [0.25]
X . XXX ± 0.005 [0.127]
ANGLES ± 0.5°
ALL ROUNDS (MAX) 0.03 [0.76]
ALL FILLETS (MAX) 0.06 [1.52]
THD ENTRY 65-75°
THD EXIT 30-45°

ALL DIAMETERS TO BE WITHIN 0.010" T.I.R.
UNMARKED ANGLES TO BE 45°± 2°
REMOVE ALL BURRS AND SHARP EDGES .005 [0.127] MIN - .030 [0.76] MAX
MACHINED SURFACES 125 RMS

DIMENSIONAL LIMITS APPLY BEFORE PROCESSES. PARENTHETICAL INFO FOR REFERENCE ONLY.
(X.XXX) INDICATES CRITICAL DIMENSION TO BE INSPECTED PER QSP W5.43-CC

	SIGNATURES	DATE
DRAWN:	MBJ	2023-05-01
CHECKED:	CB	2023-10-17
APPROVED:	MBJ	2023-10-17
WEIGHT:	81.4 LBS	

THIRD ANGLE PROJECTION

DIMENSIONS IN INCHES [MM] | DO NOT SCALE DRAWING

Tejas

4.500 X 3.750 F
HiFLO InjectGARD ASSY

018950.D-D

SCALE 1:4 | SHEET: 1:2

DO NOT MANUFACTURE WITHOUT APPROVAL STAMP

PRINT STATUS: Revision Released

Figure 3-6: Safety Valve

3.3.9 Wellhead Discussion

The wellhead proposal should be designed to combat working pressures (**Figure 3-7**). The wellhead equipment will be manufactured with a combination of alloy steel internally Xylan coated, stainless-steel and Inconel components across the hanger, casing spool, trims, stems, gates, valves, etc. The wellhead is designed with a 10,000-psi working pressure rating, FF1.5 trim tubing hanger and FF trim lower master valve, and EE trim production tree with internal Xylan coating. The wellhead equipment will contain wing valves that can be automatically controlled to shut the well in when a tubing leak is detected. Additionally, the production tree and master valve are sized to provide unrestricted access to the 4-½-in completion. Additional engineering drawings are included as a supplemental attachment.

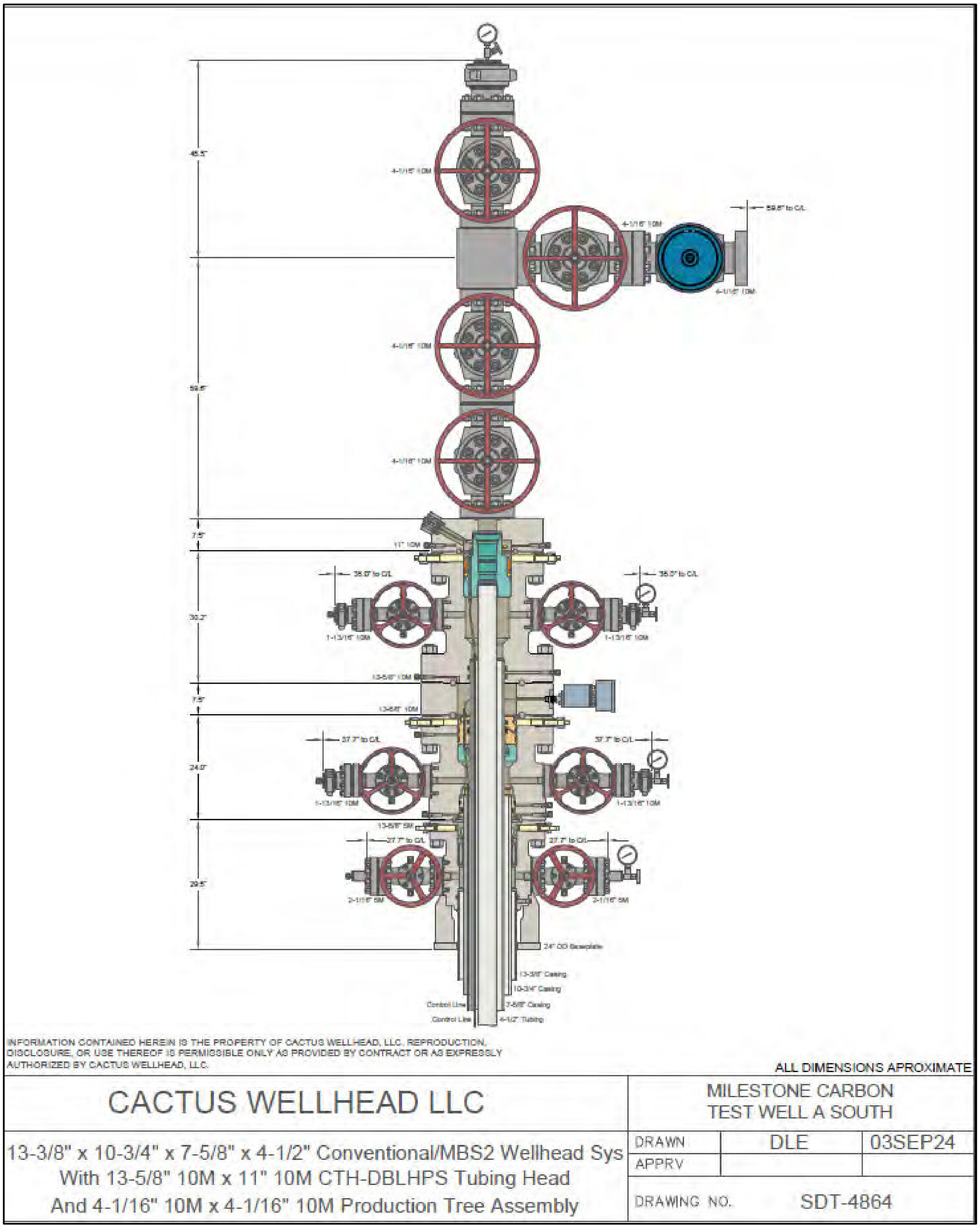


Figure 3-7: Midland CCS #2 Well Preliminary Wellhead Design

3.3.10 Packer Discussion

The production tubing will be run into the well with a 4-½-in x 7-5/8-in 22CR/25CR or equivalent permanent packer with premium connections (**Figure 3-8**). A more detailed schematic of the completion including the packer and safety valve can be seen in **Figure 3-9.**

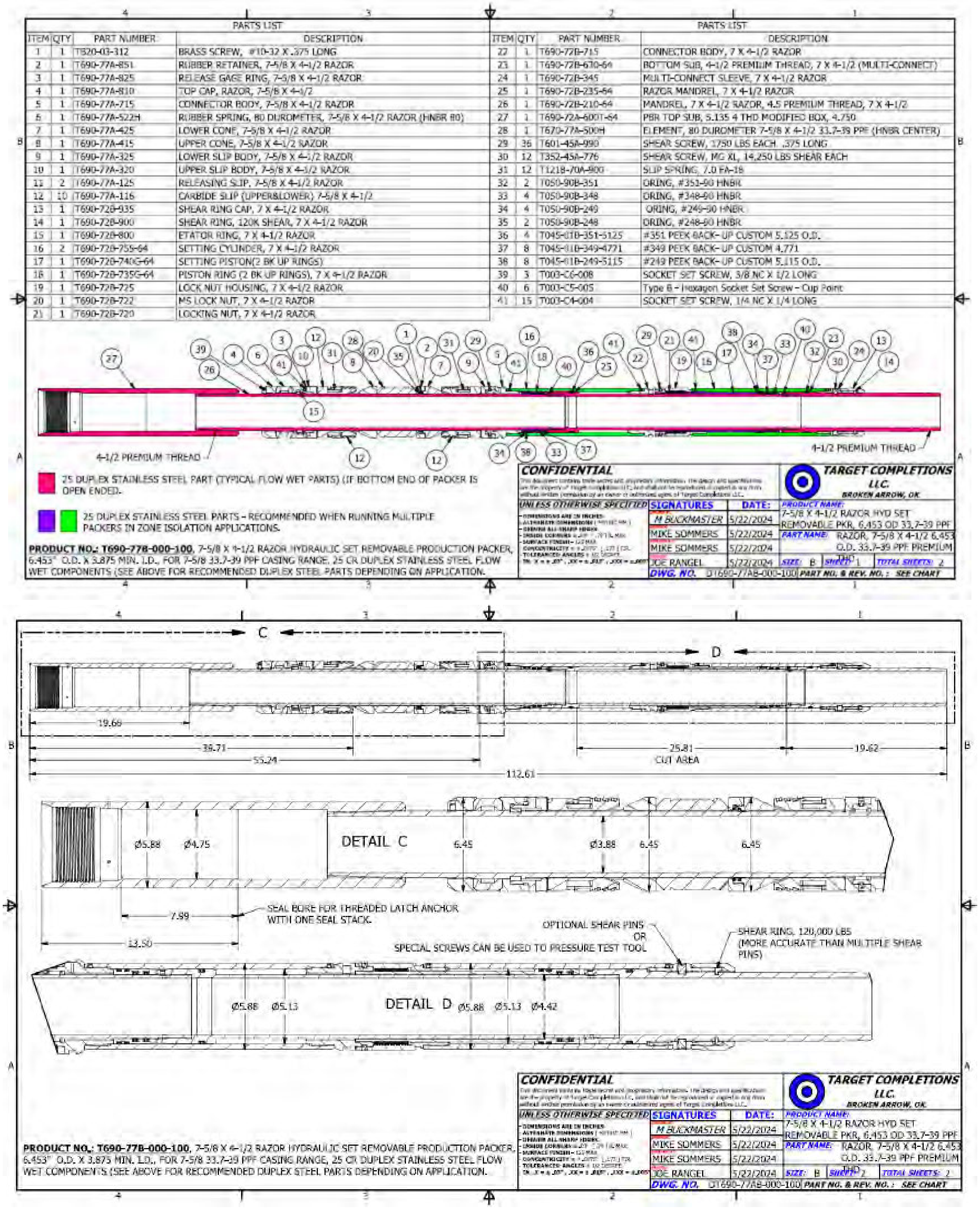


Figure 3-8: Seal Assembly, 4-½-in x 7-5/8-in Permanent Packer

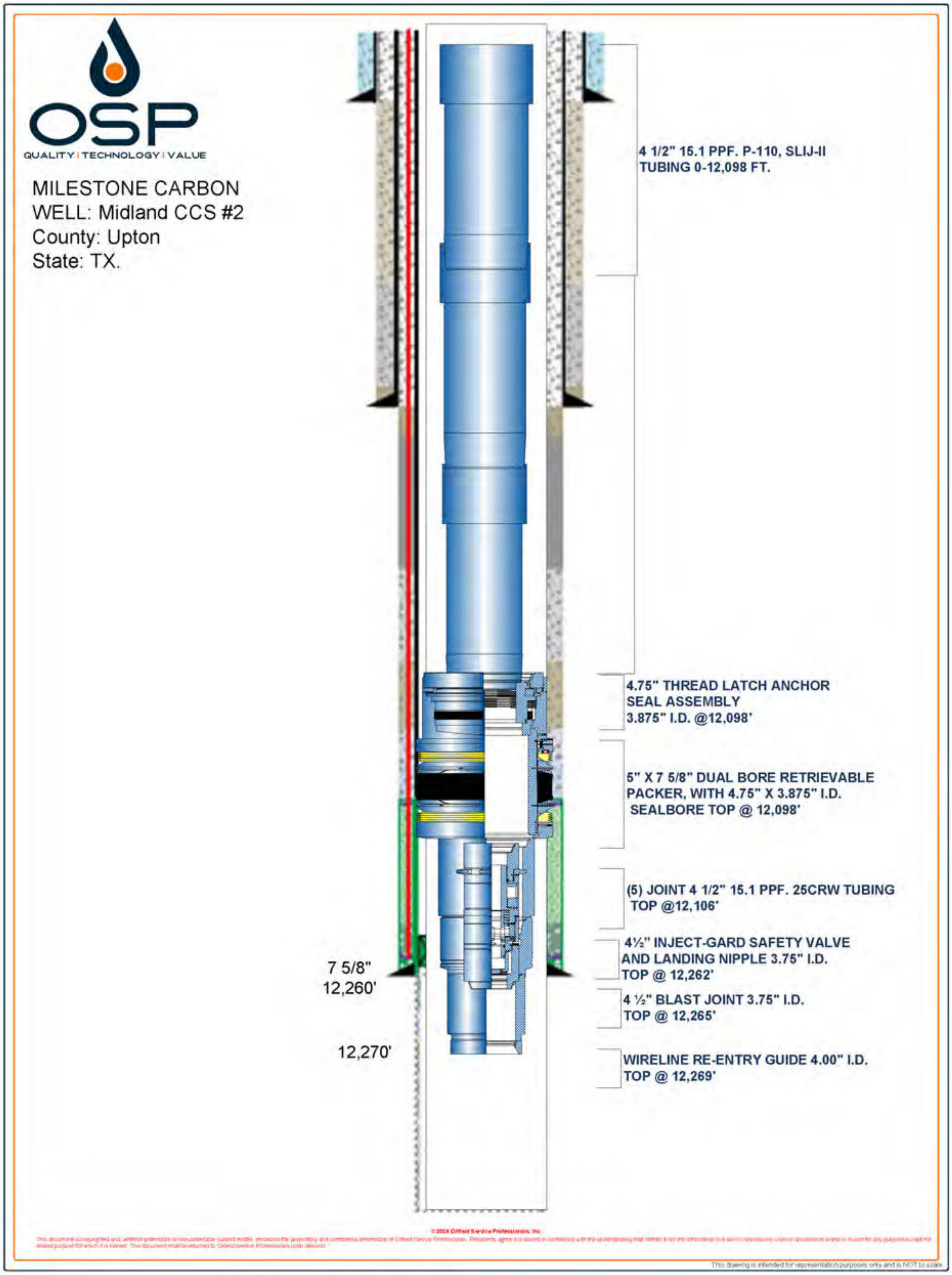


Figure 3-9: Injection Well Completion Schematic

3.3.11 Cement Discussion

Milestone will use corrosion resistant cement over any intervals that might contact injectate and formation brine in the Midland CCS #2 and Midland IZM #2. These include the Top Seal and the Injection Interval. Formations above the top-seal will use Portland cement as they are unlikely to contact corrosive fluids. No corrosive resistant cement will be utilized in wells that only penetrate the local aquifers I.E. the USDW or NSSW wells (**Figures 3-1** and **3-11**).

Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. **Figure 3-10** illustrates the compressive strength of Evercrete compared to Portland Cement when exposed to CO_2 and brine or carbonic acid over time. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well construction. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

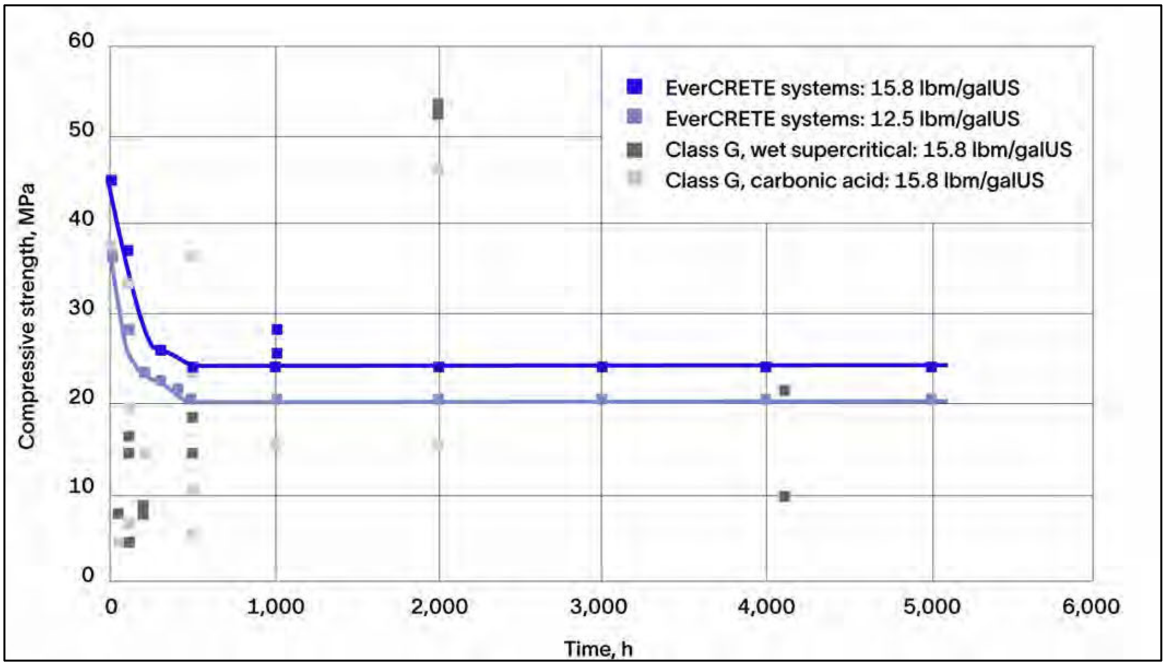


Figure 3-10: Comparison of Evercrete Compressive Strength
Evercrete(Blue) vs Portland Cement (Grey) over time when exposed to Supercritical CO2 and Brine or Carbonic Acid

3.4 In-Zone Monitoring Well

Milestone intends to drill and complete an in-zone monitoring well, Midland IZM #2, to monitor the injection zone in the Devonian and Ellenburger Formations and monitor above the Top Seal in the Pennsylvanian section. The well will utilize three (3) U-tube fluid sampling systems. One (1) in the first permeable zone above the Top Seal, likely the Strawn, one (1) in the Devonian, and one (1) in the Ellenburger group and completed with fiber optic cables. The Midland IZM #2 will be positioned approximately 3,500 feet southeast of the Injection Well. Location information can be found in **Section 1.** This well will be drilled into the injection interval; therefore, it will require corrosion-resistant materials for construction. The proposed design for Midland IZM #2 is depicted in **Figure 3-11**. See permit **Section 6** for additional information on Fiber Optic Cables. The Midland IZM #2 is currently not planned to be perforated as all testing will be performed via u-tubes or indirect methods through casing.

3.4.1 General Outline of In-Zone Well Design and Completion Schematic

Midland IZM #2 was designed with the following specifications:

1. Conductor Pipe
    a. Size: 20-in
    b. Depth: 120 ft
2. Surface Casing
    a. To be set below the lowermost USDW
        i. Currently estimated setting depth: 1,300 ft
            1. Based on offset GAU Determination letters (**Section 13, Appendix I**) issued by the RRC.
            2. Base of USDW located at 1,250 ft
    b. 13-3/8-in casing set at 1,300 ft
    c. J-55 grade tubulars
    d. 17-½-in hole size
    e. Cement to surface
3. Intermediate Casing
    a. 9-5/8-in casing set at 9,000 ft
    b. L80 grade tubulars
    c. 12-¼-in hole size
    d. Cement to surface
        i. DV Tool set at ~4,100 ft
4. Production Casing
    a. 4-½-in casing set at 13,785 ft
    b. L80 grade tubulars to 11,600 ft
    c. 25CRW or equivalent to 13,785 ft
    d. 7-7/8-in hole size
    e. Cement to surface
        i. Cement to be comprised of the following make-up:
            1. From surface to ~500 ft above the top seal – (light weight acid resistant cement)
            2. From ~500 ft above the top seal, throughout the injection interval, to shoe – (acid resistant cement)

Well Name:	Midland IZM #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,796'
Depth (TVD):	13,785'
Texas Central NAD 83	
Latitude:	31.608086°
Longitude:	-101.983038°

MILESTONE CARBON

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	9 5/8	53.5	L80	VAM 21	8.583	12 1/4	0	9,000	0
3	Production:	4 1/2	15.1	L80	SLIJ-II	3.826	7 7/8	0	11,600	0
4				25CRW	SFJ			11,600	13,785	11,600

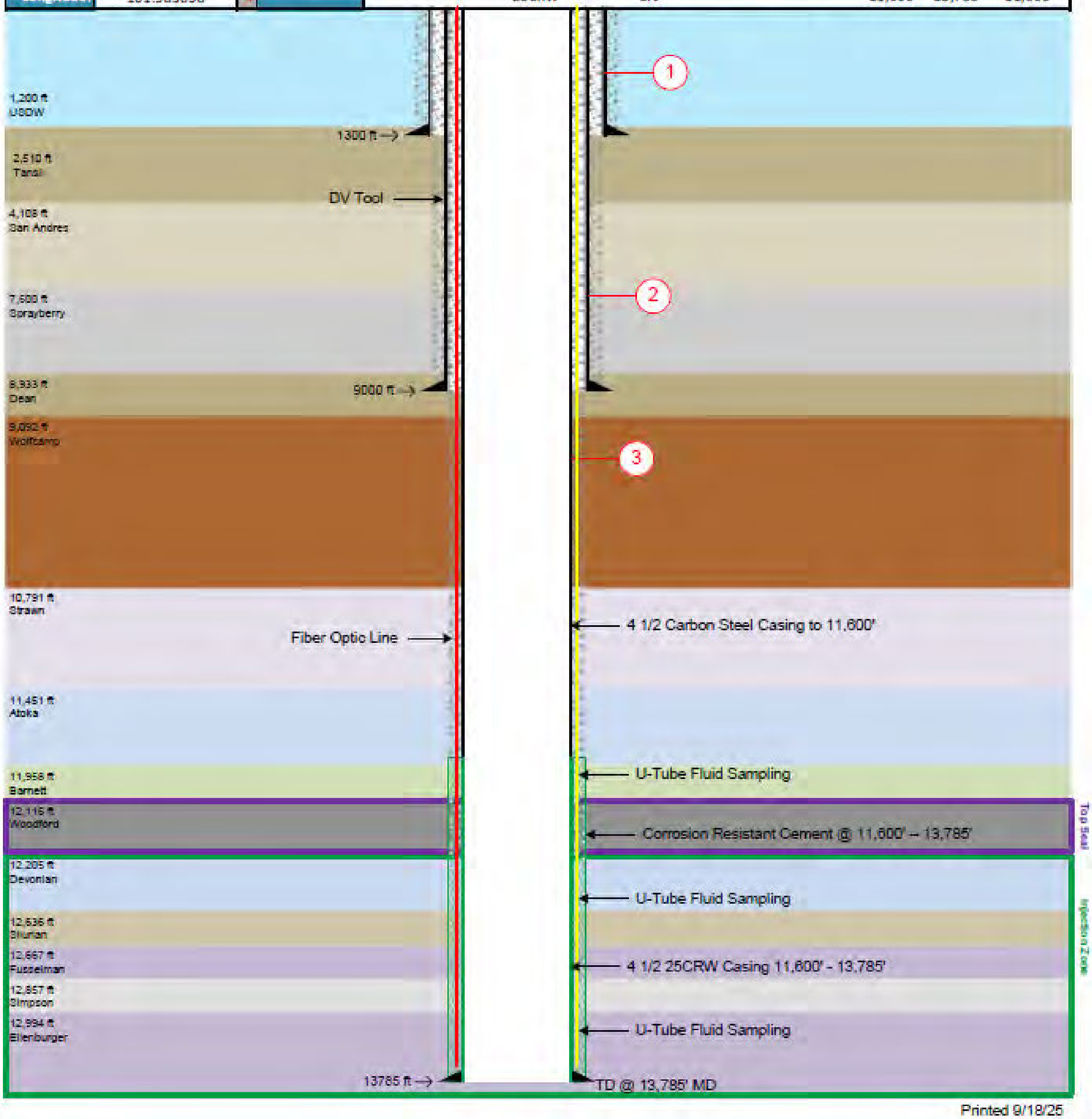


Figure 3-11: Midland IZM #2 Wellbore Schematic

3.5 USDW Monitor Well Design

Milestone intends to drill and complete one (1) USDW monitoring well, Midland USDW #2, to monitor the lowermost USDW intervals, the base of the Dockum aquifer. The Midland USDW #2 well will be positioned within 1,000 ft laterally of the Midland CCS #2 injection well and will monitor for signs of CO_2 escaping from the confinement zone and traveling up into the USDW. This well will not be drilled into the Top Seal; therefore, it will not require acid-resistant materials for construction. The well location may change pending results of hydrogeologic testing. Milestone intends to drill it updip of the injection well in the most likely path of a potential leak. The proposed design for Midland USDW #1 is depicted in **Figure 3-12**. The updip direction based on literature and testing is southwest from the proposed Midland CCS #2 injection well. This will be confirmed after drilling the NSSW wells. The proposed location of Midland USDW #1 is found in **Section 1**.

Well Name:	Midland USDW #2
County:	Upton
State:	TX
Depth (TVD):	1,300

MILESTONE CARBON

Casing Program

	OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Drift (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1 Surface:	5 1/2	14	J-55	BTC	5.012	4.887	7 7/8	0	1,300	0

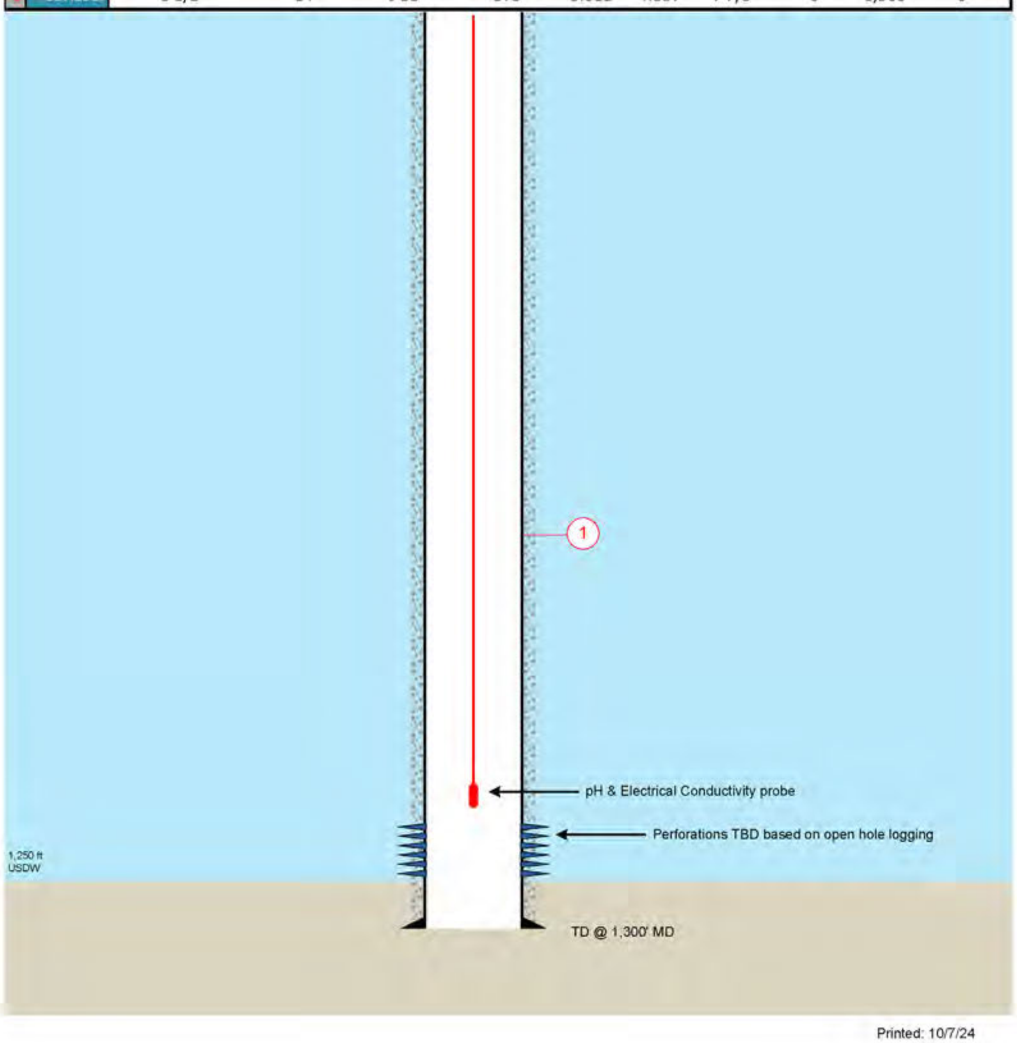


Figure 3-12: Midland USDW #2 Wellbore Schematic

3.6 Near Surface Seismometer (NSSW) Monitor Wells

Milestone intends to drill, and complete, five (5) shallow water monitoring wells with Near Surface Seismometer wells (NSSW), described further in permit **Section 6.5.2** and illustrated in **Figure 3-13**. The total depth (TD) of each well is expected to be approximately 300 feet, determined by the base of the Edwards-Trinity (Plateau) aquifer. The hole size of each NSSW will be 6-in and will contain two (2) 1.4-in PVC cementation pipes, one (1) 0.6-in seismic sensor line, one (1) 1.85-in water probe sensor, and one (1) 2-in PVC casing. The water quality probe will be set at a depth determined by logs in a slotted screen, illustrated in **Figure 3-13**. The seismometer will be cemented in place at the bottom of the well to enhance coupling with the bedrock. Baker Hughes, or equivalent, service provider will be utilized.

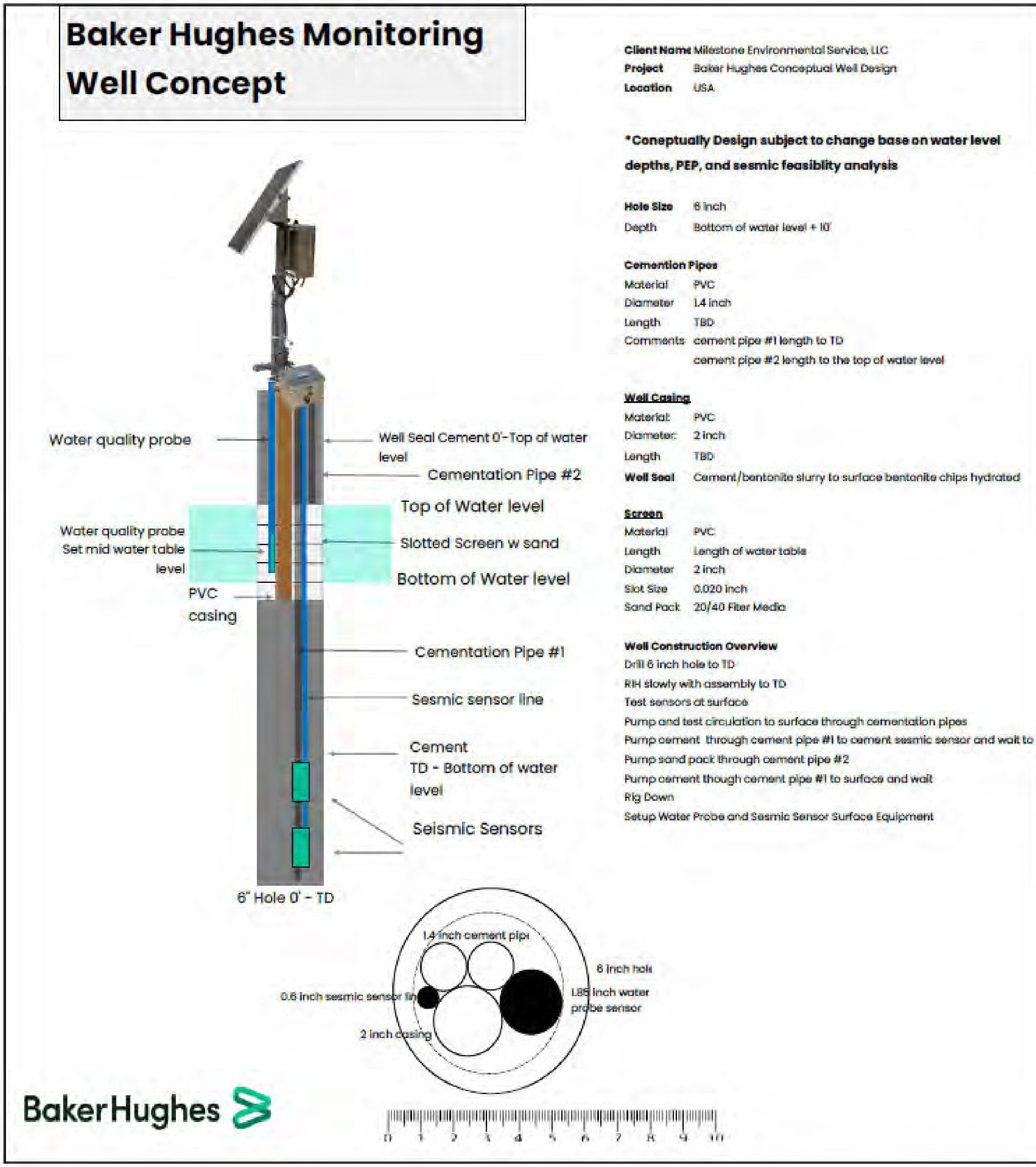


Figure 3-13: Midland NSSW Water Monitoring Wells

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment C: Stimulation Program

[40 CFR §146.82 (a)(9)]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

MILESTONE CARBON

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Updated 18 October 2024

7.0 STIMULATION PROGRAM [40 CFR 146.82(a)(9)]

Stimulation to enhance the injectivity potential of the injection zone may be necessary. Stimulation may involve, but is not limited to, flowing fluids, including acid, 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 herein, prior to conducting the stimulation.

Milestone (the permittee) will describe any fluids to be utilized for stimulation activities and will demonstrate that the stimulation will not interfere with containment. Milestone will 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). It is understood that within the 30-day notice period, TRRC may:

1. Deny the stimulation
2. Approve the stimulation as proposed
3. Approve the stimulation with conditions

Milestone will carry out the stimulation procedures, including any conditions, as approved or set forth by TRRC.

Notice and the opportunity to witness the stimulation activities will be provided to TRRC at least 48 hours in advance.

Historically, operators have stimulated the Siluro-Devonian and Ellenburger with 15% hydrochloric acid. For example, the nearest saltwater disposal (SWD) well that penetrates the Ellenburger, the Davidson Unit 1 #0106BH (API#:42-461-40597), was stimulated using 1,500 gallons of 15% NEFE HCl acid when it was completed on 12/23/2017. (**Figure 7-1**)

Once core samples are acquired, Milestone will work with best-in-class service companies to determine an appropriate stimulation program, should one become necessary.

47. ACID, SHOT, FRACTURE, CEMENT SQUEEZE. ETC.		
Depth Interval		Amount and Kind of Material Used
13600.0	14592.0	ACID WITH 1,500G 15% NEFE HCI ACID

48. FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)			
Formations	Depth	Formations	Depth
YATES	2730.0 MD: 2731.0	STRAWN	10884.0 MD: 10901.0
GRAYBURG	4491.0 MD: 4493.0	DEVONIAN	
SAN ANDRES - SALTWATER FLOW	4764.0 MD: 4767.0	FUSSELMAN	13021.0 MD: 13051.0
SPRABERRY	7400.0 MD: 7405.0	ELLENBURGER	13537.0 MD: 13568.0
WOLFCAMP	9283.0 MD: 9289.0		
REMARKS: [RRC Staff 2018-06-07 16:36:58.465]: shut-in UIC well type; operator must comply with			

Figure 7-1: Excerpt from Davidson Unit 1 #0106BH W-2 Completion form
Submitted to Railroad Commission of Texas; It is likely that Milestone will have to use a similar acid completion of the Injection Well. Source: Enverus / Railroad Commission of Texas Records

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment D: Pre-Operational Testing Program

[40 CFR §146.82(c)]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave, Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Updated 18 October 2024

Table of Contents

List of Tables

List of Figures

5.0 PRE-OPERATIONAL TESTING PROGRAM [40 CFR 146.82(c)]

Section 5 features the pre-operational testing to be undertaken by Milestone prior to commencing injection. Permit **Section 6** details monitoring activities to be performed after injection commences. Testing in this section is meant to act as a baseline for all subsequent monitoring activities.

During, and prior to, the drilling and construction of the Class VI injection wells, Milestone will run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared.

5.1 Initial Reporting Requirements

Per 40 CFR 146.87(a), within six (6) months after completion of drilling operations of any wells that penetrate the injection interval, Milestone will submit to the UIC Director a descriptive report prepared by a knowledgeable, experienced log analyst, or petrophysicist, that includes an interpretation of the results of logs, core analysis, water testing, seismicity, and any additional tests required by the Director.

Milestone will provide the Director with the opportunity to witness all logging and testing. Milestone will submit a schedule of such activities to the Director 30 days prior to conducting the first test, and if necessary, submit any changes to the schedule 30 days prior to the next scheduled test.

5.2 Initial Near Surface Water Testing

Milestone will install five (5) near-surface water sampling stations (NSSW Wells) designed to monitor water quality in the Edwards-Trinity (Plateau) aquifer. These will be installed before drilling commences. Milestone will test the water at each station at least twice in the six months preceding drilling operations and then at least once before injection commences. Water testing will follow the procedures presented in **Table 5-1** and permit **Section 13 Appendix C-QASP**. Locations of NSSW wells are located in permit **Section 1**.

Table 5-1: Pre-Operational Near Surface Water Testing Matrix

Parameter	Analytical Methods
Dissolved CO_2	Coulometric Titration, ASTM D513-11
Total dissolved solids	Gravimetry, APHA 2540C
pH (field)	EPA 150.1
Specific conductivity (SC) (field)	APHA 2510
Temperature	Thermocouple
Water Density	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Isotope ratio mass spectrometry
Alkalinity	APHA 2320B

5.2.1 Sampling and Analytical Methods

Fluid samples in NSSW Monitoring Wells will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

Water samples will be tested, and the results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

5.2.2 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

5.3 Testing and Logging During Drilling and Completion Operations

5.3.1 Ancillary Testing during Drilling Operations Prior to TD

Table 5-2 reflects tests and logs that will be conducted during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a) and (c).

Per 40 CFR 146.87 (a)(1), deviation measurements will be conducted approximately every 100 ft during construction of the well using a gyro tool or similar device. Azimuth, inclination, offset, measured depth (MD) and TVD will be reported. Additionally, deviation will subsequently be sampled at 0.5-ft increments during wireline logging using the orientation tool in the image log.

Experienced mudloggers will be on location to take samples at approximately every 500 ft above the top seal and approximately every 20 ft in the top seal and injection units. C1-C5 gas, H_2, He, CO_2, N_2 and H_2S measurements will also be obtained as part of the mud logging. Isotubes® of gas samples will be acquired and retained for later isotopic and chemical testing to verify geologic seals.

Measurement while drilling (MWD) gamma ray measurements will be obtained during drilling operations to aid in offset well correlation. This measurement data will also be indispensable for determining core point.

Table 5-2: Ancillary Testing During Drilling Operations
Not including Wireline and Coring

Ancillary Testing	Main Objective
Mud Logging	Take physical samples of Rock while Drilling, early warning of changes in thickness or lithology
Gas Chromatography	Measure mud gas, Hydrocarbons and Inert gasses, Samples will be preserved in isotubes®
Deviation Measurements	Measure inclination, azimuth, and TVD of well
MWD gamma ray	Validate offset well correlation of formation tops

5.3.2 Wireline Logging Program

Per 40 CFR 146.87(a)(2)(i) and 40 CFR 146.87(a)(3)(i), before casing is installed, openhole log data will be acquired reflecting in-situ, structural, stratigraphic, physical, chemical, and geomechanical information for 1) the Woodford shale top-seal, 2) the Siluro-Devonian and Ellenburger injection units and, 3) other zones of interest above or within the injection and confining units/intervals.

Wireline conveyed openhole logs will be acquired at the surface casing point, intermediate casing points, and production casing point. Openhole logs will not be acquired in the conductor casing hole.

Milestone will log the Midland CCS #2 and Midland IZM #2 wells. There are several logging requirements necessary to meet EPA standards and responsible operation which include standard logs (Triple Combo) advanced logs and mechanical integrity logs (MIT) (**Figure 5-1**).

The logging program consists of four separate logging jobs: one for surface hole, two for first and second intermediate holes and one for production hole (**Figure 5-1**).

- **STANDARD LOGS** include the gamma ray or spectral gamma ray, resistivity, neutron, density, caliper, and spontaneous potential. These data are used for primary reservoir and fluid characterization including lithology, porosity, salinity, fracture identification, indications of permeability, and fluid saturations. Standard logs can answer most of the primary reservoir questions related to storage volume.
- **ADVANCED LOGS** include monopole and dipole sonic tools, resistivity imaging, nuclear magnetic resonance (NMR), neutron spectroscopy, formation pressure testing and fluid sampling. These are used to complement the standard logs and give additional formation information such as pore body sizes, detailed chemical and elemental information, and finally geomechanical information. These advanced tools are necessary to meet the requirements of documents 40 CFR 146.87 and 40 CFR 146.86.

The sonic tool is a secondary porosity tool, but is also key in understanding geomechanics, stress direction, and existence of fractures in the reservoir and confining layers. The sonic tool will be used to acquire a 3-D shear survey for approximately 50 ft around the wellbore.

The geomechanical interpretation is bolstered by the image logs which can be interpreted for fracture identification, stratigraphy, stress direction, and dip. The image log can also be used to calculate maximum principal stress magnitude in conjunction with sonic data. ***The image log will be critical to identify fracture frequency and fracture aperture and evolve the reservoir model accordingly.***

The NMR tool can be used to approximate pore body geometry in conjunction with MICP or Brunauer-Emmett-Teller (BET) data. It is very useful for estimating permeability as well since it measures hydrogen precession and pore relaxation effects.

The neutron spectroscopy tool gives detailed highly accurate measurements of several elements such as Si, Ca, Mg, Al etc. and can be used with a mixing model and in conjunction with XRD and XRF data to create a detailed vertically continuous mineral model.

The dielectric log will be run to measure bulk volume water and give an additional continuous measure of salinity that can be used in conjunction with other measurements to calculate water resistivity (R_w), the cementation/porosity exponent (m) and the saturation exponent (n).

The formation tester will be used to determine formation pore pressure and mobility through pretests. The gradient produced through the interpretation of individual pore pressures indicate zones of over- or under-pressure, and the potential for different reservoir compartments. With viscosity as a known variable, the permeability can be easily estimated from mobility or through post sample buildups.

In-situ samples acquired at multiple depths will determine the physical and chemical properties of the water, as well as flowing temperature of the fluid. Using a formation testing tool, in concert with a dual packer, will allow the acquisition of a fracture gradient for the confining layers and injection units. This will allow for management of injection rates to maintain an effective seal. The advanced logs can answer most of the remaining borehole questions including vertical connectivity, producibility, fluid chemistry, and geomechanics.

Milestone will exhaust all efforts to source tools that fit within the inner diameter of the tubulars. However, there remains a slight/unlikely chance that tools of the appropriate size may be unavailable.

5.3.2.1 Surface and First Intermediate Logging Program

The surface and intermediate hole logging program, as shown in **Table 5-3**, includes the five (5) logs, along with the main objectives. In the initial phases, a triple combo with spectral gamma ray, in addition to dipole sonic will be utilized. This will give estimates of uphole porosity, clay content and yield a useful seismic tie as well as indications of pore pressure and geomechanical properties. After the casing is set, a cement bond long (CBL), temperature, and noise log will be run for mechanical integrity.

Table 5-3: First Intermediate and Surface Hole Logging Program Objectives

Intermediate Hole Logging Programs	Main Objective
Triple Combo and Spectral Gamma Ray and Caliper	Characterize the Spraberry and Wolfcamp Formation
Cross Dipole Sonic	Characterizing rock geomechanics properties of Spraberry and Wolfcamp including anisotropy
CBL	Cement evaluation
Temperature and Noise Log	Initial leak detection of tubing or casing

5.3.2.2 Second Intermediate Logging Program

In the second intermediate logging run, as presented in **Table 5-4**, triple combo with spectral gamma ray, dipole sonic, image logs, nuclear magnetic resonance (NMR) and neutron spectroscopy logs will be conducted. Resistivity and an ultrasonic micro imager will yield fracture frequency, orientation, and aperture as well as borehole induced tensile fractures plus breakout. Sidewall cores will be acquired if a whole core cannot be obtained in the Top Seal – Woodford Shale.

If drilling conditions permit, fluid and pressure samples will be taken in the Strawn or other permeable zone above the top seal as an additional baseline fluid sample. If a fluid sample cannot be obtained above the Top Seal while logging, it will be captured after completion from one of the permanent U-tube systems installed in the monitoring well.

Table 5-4: Second Intermediate Logging Program and Objectives

Intermediate Hole Logging Programs	Main Objective
Triple Combo and Spectral gamma ray and caliper	Characterize the Spraberry and Wolfcamp Formation
Cross dipole Sonic	Characterizing rock geomechanics properties of Spraberry and Wolfcamp including anisotropy
USIT and CBL	Cement evaluation
Resistivity and Ultrasonic Imager	Identify fractures, faults, wellbore breakouts and tensile fractures. Improve the characterization of geomechanics properties, stress orientation, amplitude, and anisotropy
Neutron Spectroscopy	Elemental composition to characterize lithology
Nuclear Magnetic Resonance	Pore size, pore geometry, porosity and permeability
Formation Tester	Directly measure the pore pressure and take fluid sample from the Strawn
Temperature and Noise Log	Initial leak detection of tubing or casing
Dielectric Log	Additional measure of formation salinity (Rw), *m* and *n*
Rotary Sidewall Cores	Side wall cores will be taken if whole coring fails or is not safe

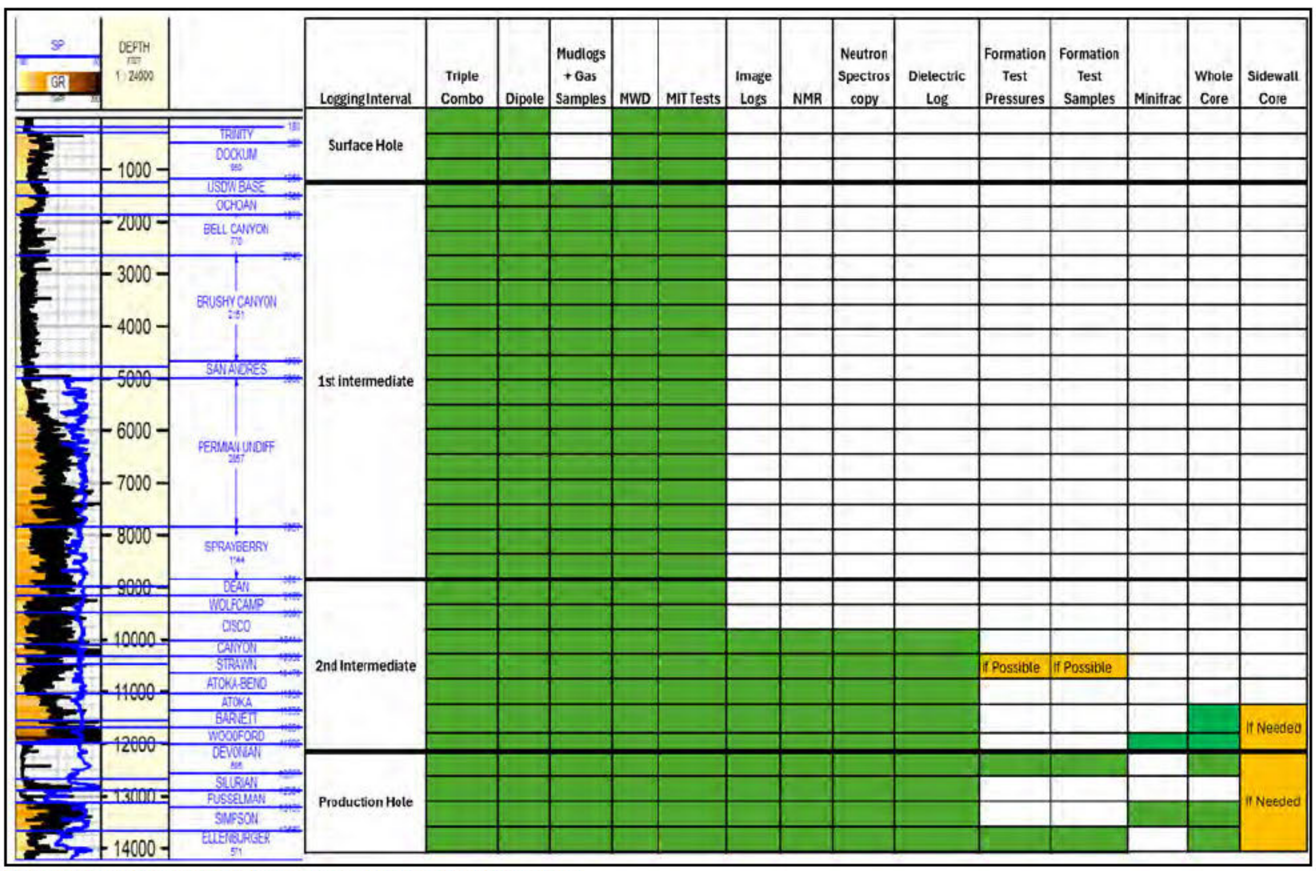


Figure 5-1: Proposed Logging and Coring Program

5.3.2.3 Program Production Hole Logging Program

The production hole logging program includes the logs, and their main objectives, presented in **Table 5-5** and **Figure 5-1**. This is the most comprehensive logging program in the project. A triple combo with spectral gamma ray will be used for standard properties such as density and resistivity. A neutron spectroscopy will be used for elements and minerals. NMR will characterize pore size and permeability index. A dipole sonic will be used to estimate geomechanical properties, tie the 3D seismic, indirectly measure pore pressure, detect vugs, and measure fractures away from the borehole using a far-field shear survey. Sonic tools can also be used as secondary porosity measurement. Sidewall cores will be acquired if the whole core fails to recover or cannot safely be achieved.

Resistivity and the ultrasonic micro imager will yield fracture frequency, orientation, aperture as well as borehole induced tensile fractures plus breakout. The imager logs are critical to future modeling as the injection interval is expected to be heavily fractured.

Formation testing will take pressure tests, fluid samples and finally minifrac the formation at the conclusion of the logging job. If a fluid sample cannot be obtained while logging, it will be captured after completion from one of the permanent U-tube systems installed in the monitoring well or by producing the completed injection well prior to injection.

Cement will be evaluated for bond, consistency, and height using cement bond log, ultrasonic casing inspection tool, magnetic flux leakage and a multi-finger caliper. A pulse neutron log will be used to measure initial gas saturation before injection. Additionally, an oxygen activation log will be performed using the pulse neutron as a baseline and a temperature noise log will be obtained as a baseline and to calibrate Distributed Acoustic Sensing/Distributed Temperature Sensing (DAS/DTS).

Table 5-5: Production Hole Logging Program and Objectives

Production Hole Logging Programs	Main Objective
Triple Combo and Spectral Gamma Ray and Caliper	Determine lithology, resistivity, porosity, and fluid salinity. Triple combos are the backbone of any petrophysical interpretation.
Neutron Spectroscopy	Elemental composition to characterize lithology
Nuclear Magnetic Resonance	Pore size, pore geometry, porosity and permeability
Cross-Dipole Sonic	Velocities for geophysical ties, geomechanical attributes, indirect pore pressure, secondary porosity log, vugs, acoustic anisotropy, far field shear survey for fractures away from well
Resistivity and Ultrasonic Imager	Identify fractures, faults, wellbore breakouts and tensile fractures. Improve the characterization of geomechanics properties, stress orientation, amplitude, and anisotropy
Formation Tester	Directly measure the pore pressure and take fluid sample from the Siluro-Devonian, and Ellenburger units
Microfrac	Microfrac testing seal and reservoir for fracture gradient
Ultrasonic Casing Inspection Tool (USIT) and Cement Bond Log (CBL)	Initial cement integrity
Multifinger Caliper	Initial casing geometry

EM Flux	Initial casing corrosion
Pulse Neutron	Initial gas saturation near the wellbore before injection begins, also oxygen activation log for MIT
Temperature and Noise Log	Initial leak detection of tubing or casing
Dielectric Log	Additional measure of formation salinity, *m* and *n*
Additional Mechanical Integrity Tests	See **Table 5-7**
Rotary Sidewall Cores	Side wall cores will be taken if whole coring fails or is deemed unsafe

5.3.3 Formation Fluid Testing

Prior to setting the production casing string, samples of formation fluid will be obtained by running an openhole formation testing tool after successful pre-pressure tests. Recovery sections and sample depths in the injection interval will be determined based on openhole evaluations.

Milestone will work with logging vendors to utilize the best possible approach to formation testing design. Within the Ellenburger and Siluro-Devonian units, it is likely a dual packer configuration will be utilized to maximize surface area across fractured intervals. Smaller probes may be used in the intermediate section of the hole to reduce testing time.

Milestone will strive to collect the maximum number of samples; however, potential tool malfunctions may necessitate adjustments to the operational plan. Milestone will make the best possible efforts to acquire the number of samples listed below in a) through c) (see permit **Section 1** for definition of units):

a) Two samples in Ellenburger injection unit
b) Two samples in Siluro-Devonian injection unit
c) Two samples above Woodford, likely in Strawn formation

Per 40 CFR 146.87(d)(3), all samples will use rigorous fluid testing programs that include cations, anions, salinity, specific conductance, hydrogen isotopes, oxygen isotopes, and carbon isotopes as well as additional parameters. Samples will be held in sealed containers and opened in a qualified commercial lab. Formation gases will be captured. Initial testing will be identical to the proposed water testing matrix during monitoring period in order to measure proper baselines (**Table 5-6**).

Per 40 CFR 146.87(c) Milestone will record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of all tests during field operations.

Table 5-6: Water Testing for Water Samples Acquired from Formation Testing

Parameter	Analytic Method
Dissolved CO_2	Coulometric Titration, ASTM D513-11
Total dissolved solids	Gravimetry, APHA 2540C
pH (field)	EPA 150.1
Specific conductivity (SC) (field)	APHA 2510
Temperature	Thermocouple
Water Density	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Isotope ratio mass spectrometry
Alkalinity	APHA 2320B

5.3.4 Minifrac Testing

Per 40 CFR 146.87 (d)(1), during the openhole logging program and prior to any stimulation work, a minifrac test will be completed to measure the fracture gradient of the confining and various injection unit(s) in the Well. This test will be conducted using a formation pressure and fluid recovery tool. Testing parameters will follow Zoback et al., 2003. American Society for Testing and Materials (ASTM) Method D 4645-08, Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method (ASTM, 2008). Minifracs will be performed at depths that will not endanger the primary seal or secondary seal. A 100ft buffer zone will be utilized, or an alternative prudent buffer zone will be identified where the probability of fractures growing out of the seal is low. This buffer zone will be identified using dipole sonic and image logs.

5.3.5 Initial Mechanical Integrity Demonstration and Hydrogeologic Testing

Table 5-7 is a summary of the Mechanical Integrity Tests (MIT) and pressure fall-off tests to be performed prior to injection.

Milestone will notify EPA at least 30 days prior to conducting the test(s) and provide a detailed description of each testing procedure. Notice, and the opportunity to witness these tests/logs, shall be provided to EPA at least 48 hours in advance of a given test/log.

All tests will utilize the latest EPA guidelines. See permit **Section 6** and **Section 13 Appendix C: QASP** for pressure fall-off testing procedures and guidelines.

Table 5-7: Pre-Operational Mechanical Testing Schedule

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.87(a)(4)(i) 40 CFR 146.89 (b)	MIT	Annulus Pressure Test	1 hour after isolation
40 CFR 146.87(a)(4)(ii) 40 CFR 146.89(c)(1)	MIT	Tracer Log Pulse Neutron (Oxygen Activation)	8 Hours
40 CFR 146.87(a)(4)(iii)	MIT	Temperature and Noise log	8 Hours
40 CFR 146.87(a)(4)(iv) 40 CFR 146.87(a)(2)(ii) 40 CFR 146.87(a)(3)(ii)	MIT	Multifinger Caliper, EM flux, Cement Bond Log, Ultrasonic Inspection Tool	8 Hours
40 CFR 146.87(e)(3)	Verify Hydrogeologic Characteristics of Zone	Step Rate Injection Test	60 minutes per step, at least 5 steps
40 CFR 146.87(e)(1)	Verify Hydrogeologic Characteristics of Zone	Pressure Fall-Off Test	1 Week, or until radial flow achieved for 24 hours
40 CFR 146.87(e)(2)	Surface Equipment Test	Pump Test	1 Hour

Per 40 CFR 146.87 and 40 CFR 146.89, the planned cased-hole logs that will be run include several tools meant to establish baselines for future mechanical integrity monitoring. These casing inspection baseline logs include cement bond logs, noise log, temperature log, ultrasonic inspection tool, a pulse neutron log, an EM flux log, multi-finger caliper and an oxygen-activation log. Future logging of this unit, with the same technology, will allow for monitoring of the plume and the mechanical integrity of the wellbore. Minimum tool diameter may limit some of the proposed logging activities and will be reviewed when a vendor is selected. Best efforts will be made to source a viable tool.

5.4 Coring Testing Program [146.87 (b)]

5.4.1 Core Acquisition

Core acquisition is planned to include four (4) discrete runs of whole core and infill, if necessary, by rotary sidewall coring conveyed from wireline. The entire core program is shown in **Table 5-8**. Depths may be altered as additional information becomes available from 3D seismic data, uphole surface logging, as well as MWD measurements during drilling.

Milestone will core the first well in the injection interval, but may not core subsequent wells if previous cores and wireline surveys prove representative of new well conditions or if drilling conditions make core retrieval impossible. Core thicknesses may be reduced if drilling conditions deteriorate or if recovery is low. If whole coring cannot be completed due to adverse drilling conditions, sidewall cores will be utilized as an alternative.

Coring intervals are prescribed as: 1) primary Top Seal of the Woodford Shale; 2) Fusselman where the most intense fracturing is expected in the Siluro-Devonian injection unit; 3) Lower Simpson Group into Ellenburger to characterize the seal-injection interface and, 4) the Middle Ellenburger where the most intense fracturing is expected. The basement will not be sampled due to the technical challenges with coring granite, as well as the potential hazards of creating conduits in the basement rock. Since the primary Top Seal of the Woodford is not 180 ft thick, but the core barrel assembly is 180 ft, sections of the Barnett and Devonian will likely be sampled in the first coring run. Depths of coring intervals are illustrated in **Figure 5-1.**

Table 5-8: Coring Program

Interval	Lithology	Approximate Depth (ft)	Approximate Thickness of Core (ft)
Top Seal – Woodford Shale; Additional core coverage of Barnett and Devonian top	Organic Shale, Packstone	12,040	180
Silurio-Devonian	Chert-Packstone	12,500	180
Base of Simpson Group-Top of Ellenburger Group	Shale-Dolostone	13,000	180
Ellenburger Formation	Dolostone	13,300	180
Rotary Sidewall Coring	Various	Rotary Sidewall Coring throughout Production Hole, some samples may be above primary seal. Samples will be selected based on openhole logs.	50 Samples

5.4.2 Special Note on Lower Confining Layer

Since the lower confining layer of the Ellenburger formation is the Cambrian-aged Bliss sandstone or granitic or rhyolite basement, the core analysis and drilling program plan is to stop drilling 100 ft above basement rock. This stoppage is intended to reduce seismicity risk. In this plan, we will not have core or log analyses over the granitic basement, but the borehole will also not interact with basement rock unless CO_2 saturated water moves against buoyancy and travels downward due to gravity through fractures. While this downward migration is possible, the 100 ft. buffer zone is intended to mitigate this potential risk. Therefore, Milestone will not core or log the lower confining layer, which is granitic basement, in an effort to reduce seismicity risk.

This project is **not** applying for a depth waiver under [40 CFR 146.95] and [40 CFR 146.95a]. Therefore, the requirements under [40 CFR 146.95 and 146.95a] do not apply. The injection interval is 10,950 ft below the base of USDW. See permit **Section 1.4** for additional information on the base of USDW in the region.

5.4.3 Core Analysis Program

As part of the appraisal well program within the South Midland Facility, core and reservoir fluid analysis programs are planned. The core and fluid analysis programs are meant to help minimize the risk and reduce the uncertainties within the subsurface data and provide a complete dataset for the second generation static and dynamic models. The current subsurface model lacks data density in nearby area. The nearest core data is from older 1950s cores that were extracted from the Midland Basin and are presently housed at BEG.

The objective of the core and fluid analysis program is to close data gaps that impact the three principal drivers (i.e., capacity, injectivity and containment) for confirming the Siluro-Devonian and Ellenburger as a safe and secure CO_2 sequestration complex within the area. Based on log analysis results this campaign may be amended to include additional tests. The data gathering campaign is designed to:

a) Better define formation-specific permeability and porosity as well as the degree of connectivity between the Siluro-Devonian and Ellenburger units (capacity and injectivity)
b) Determine the extent to which the Woodford Shale will act as a seal to the upward migration of CO_2 (containment)
c) Provide data to calibrate well logs
d) Confirm reasonable similarity with the 1st generation static and dynamic models
e) Provide rock mechanical information
f) Provide information about threshold entry pressures and other SCAL properties
g) Provide geochemical information and fluid reactivity information
h) Further constrain mineralogy and fracturing

The analytical program will consist of two major phases as follows:

1. **Phase I**: Core analysis, fluid characterization, core description and petrography
2. **Phase II:** Special core analysis

5.4.4 Phase I: Core Analysis, Fluid Characterization, Core Description and Petrography

The main objective of this phase is to evaluate the integrity of the core and characterize both the seal and the main injection Interval along with reservoir fluids. This should yield a breakdown of the different facies that supports sample selection for special core analysis tests. The steps related to this phase are as follows and illustrated in **Figure 5-2**.

a) Core gamma measurements and CT scans are conducted on the entire core upon arrival in the lab, to review core condition and for plug selection.
b) Plug CT scan and micro-CT for shale plugs prior to SCAL
c) Plug Cleaning using Soxhlet extraction.
d) Basic rock properties for reservoir section are measured via conventional core analysis at ambient and stress conditions.
e) Klinkenberg and brine permeability, grain density, porosity. Establish Kv/Kh relation.
f) Unconventional Reservoir Workflow for shale sections- Plug Sample Includes micro-CT image AR gas saturations and total porosity by NMR. Steady State permeability and dry bulk density, porosity, and grain density by Boyle's Law.
g) Basic petrography work on selected sand and shale samples to support operational and well evaluation key needs (SEM, Thin Sections)
h) Upon plug selection and core slabbing, a core geological description should be carried out that includes fracture identification and count.
i) MICP for both reservoir sections and shale.
j) Geochemical characteristics via XRD, XRF and FTIR
k) Brine Chemistry and Salinity.

Conventional Core frequency of sampling will be at one sample 3-ft for reservoir and seal section subject to review and adjustment once the core is retrieved.

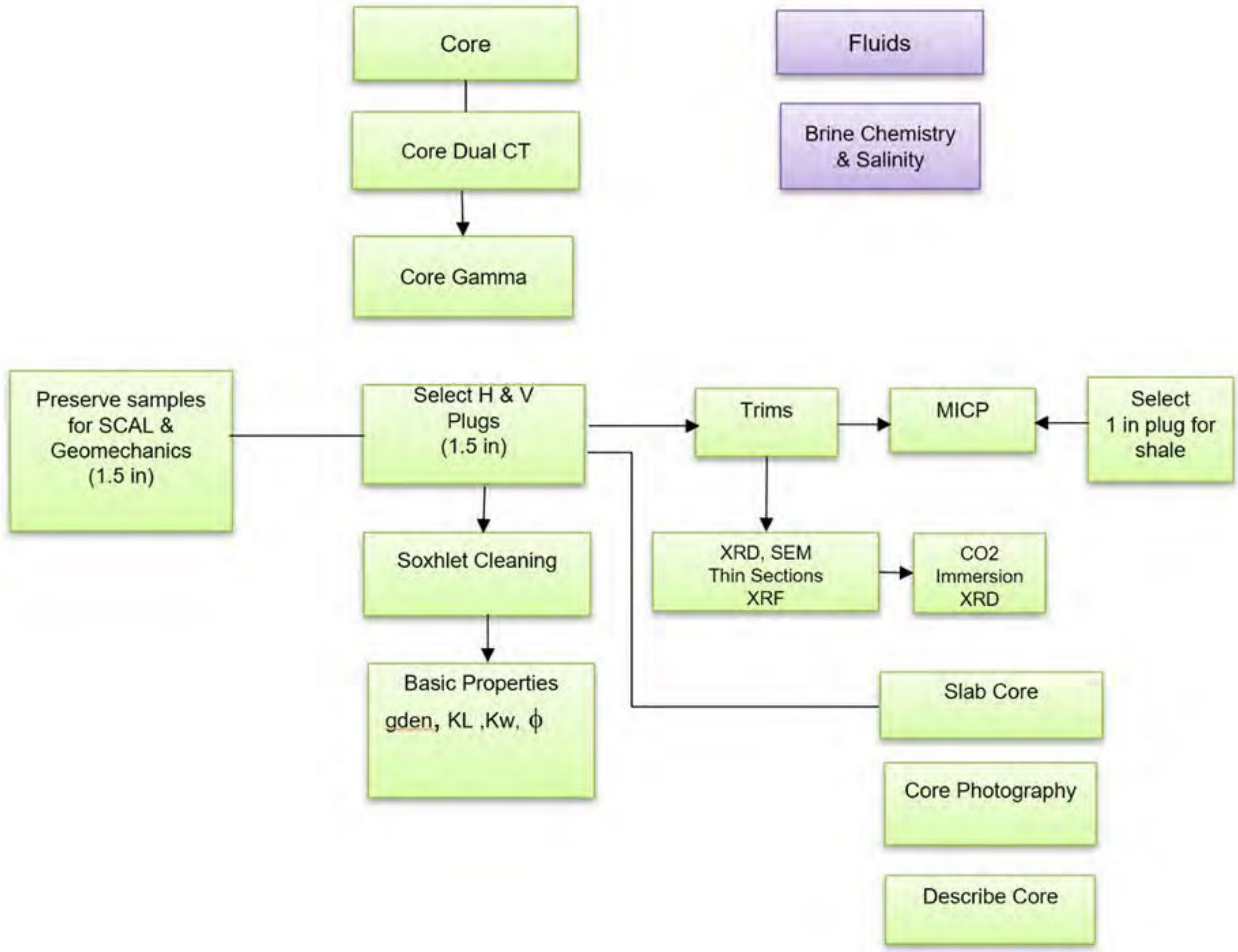


Figure 5-2: Phase I Core Analysis Program Flow Diagram*
** May be amended in consultation with an experienced commercial core laboratory*

5.4.5 Phase II: Special Core Analysis

This is the most comprehensive analytical effort, consisting of special core analysis measurements for static and dynamic data of sand facies and seals. Workflow diagramed in **Figure 5-3**. See **Section 13 Midland Appendices, "Glossary of Acronyms, Abbreviations and Terms."**

Reservoir Carbonates:

- Additional petrography work (TS, SEMs, XRDs) on trims from SCAL samples
- Flow through cleaning
- Brine preparation and properties (Resistivity, PH, density, viscosity and IFT)
- Sample saturation
- Electrical properties (FRF, RI, CoCw, m, n)
- Air-Brine Pc by centrifuge and measure Kair@Swi
- CO_2 flooding and Kg@Swi
- Brine-oil centrifuge
- CO_2 immersion XRD test to assess CO_2 effect on minerals
- Threshold entry pressure to CO_2
- CO_2 flood to assess halite precipitation (post SEM is required)
- USS Kr supercritical CO_2/brine and Brine/CO_2 end point relative permeability (followed by Dean & Stark for mass balance)

- SS Kr supercritical CO_2/brine with ISSM full relative permeability curve on few samples. Collect effluent samples for IC and ICP
- SS Kr Brine/supercritical CO_2 with ISSM full relative permeability curve on few samples. Karl Fisher is performed after the test for mass balance.
- Rock Mechanics: Triaxial, TWC, UCS, Ductility and Tensile Strength
- Rock Physics: Pore Volume Compressibility, Compressional & Shear Velocity

Seal Characterization:

- Additional shale petrography work: TS, SEMs, XRDs, XRF
- CO_2 immersion XRD test to assess CO_2 effect on minerals.
- Rock Mechanics: Triaxial, UCS, Ductility and Tensile Strength
- Rock Physics: Compressional & Shear Velocity
- Brunner Emmet Teller (BET): the specific surface area and porosity distribution

Dozens of selected samples will be acquired for SCAL testing from the reservoir section and seal section. The sampling strategy will be guided by geological rock types. Whole core sections should be preserved for geomechanics sampling. SCAL should always be prioritized over conventional core analysis, and it is recommended that samples be acquired before slabbing.

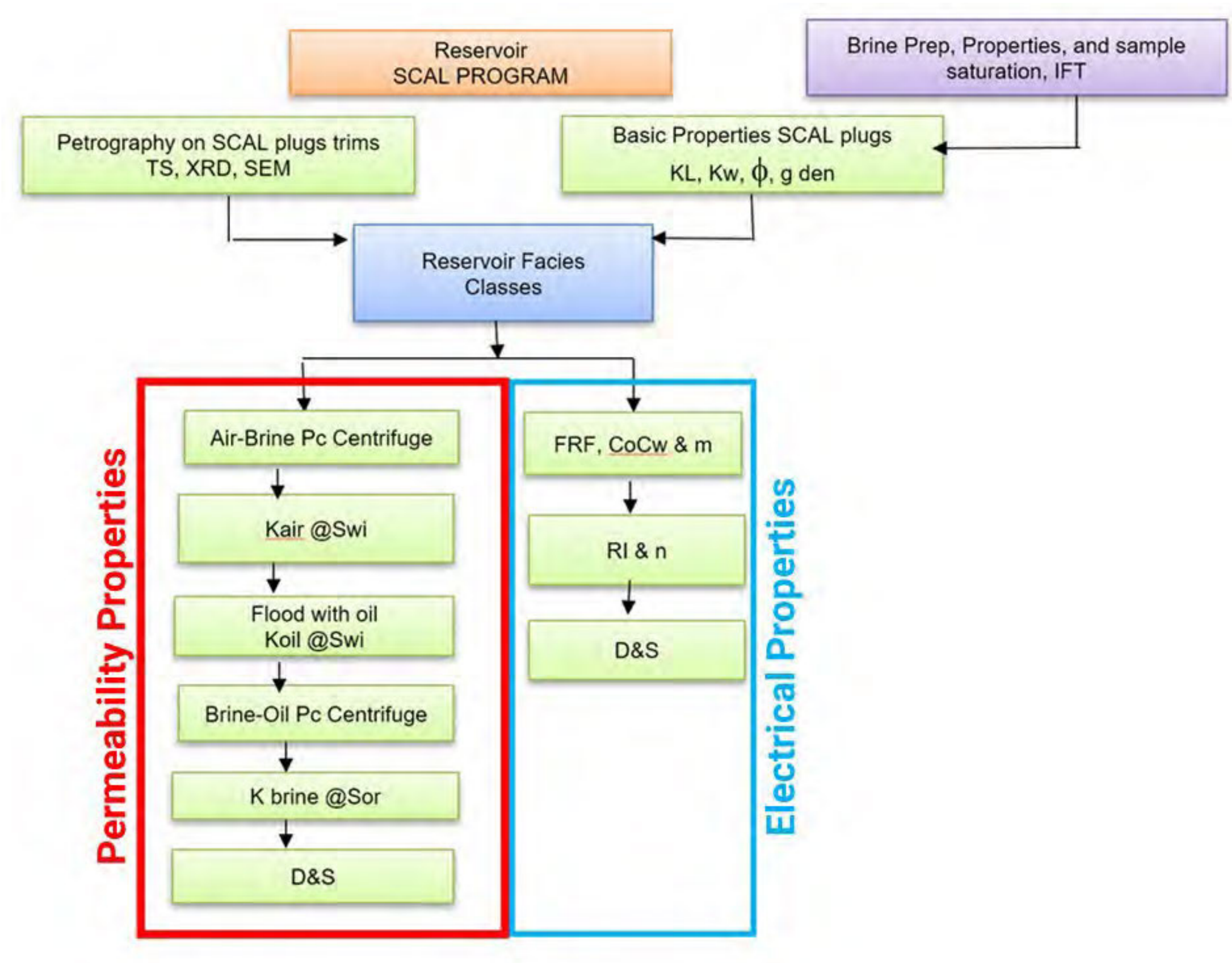


Figure 5-3: Special Core Analysis (SCAL) Flow Diagram*
** May be Amended in Consultation with an Experienced Commercial Core Testing Laboratory*

5.5 Initial Seismicity Monitoring

Before injection well drilling operations commence, five (5) near surface seismicity and water sampling stations will be installed. These wells will record seismicity continuously for at least (6) months before drilling the injection wells. Locations of the NSSW wells are noted in permit **Section 1**.

In addition to Milestone-owned stations, existing TexNet seismicity stations will also be utilized to locate any seismic events within 10km of the AoR. If a seismic event over magnitude 4.0 is recorded within 10km of the AoR and within the six-month period preceding drilling, the EPA UIC Director will be notified within 72 hours. See permit **Section 6** for more information on seismicity monitoring and magnitude of completeness modeling in the area.

5.6 Artificial Penetration Search

Milestone will conduct ground-based and aerial reconnaissance to attempt to locate additional artificial penetrations. Drone-based magnetometer surveys will be used to locate undocumented wells and personal gas detection equipment will be used to identify leaking historical wells. Milestone has completed a survey of structures, visible wells in the area, and a paper records review.

Within the AoR, Milestone has already located 71 oil and gas wells and 87 water wells. Milestone will attempt to locate any additional wells that are not recorded.

See permit **Section 1** for additional information on the locations of these wells. None of the currently known wells penetrate the Top Seal or injection interval.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment E: Operational Strategy

[40 CFR §146.82, §146.86, §146.87]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Prepared by

Numeric Solutions, LLC

1536 Eastman Ave, Suite D

Ventura, California 93003

Updated 18 October 2024

Table of Contents

List of Tables

4.0 OPERATIONAL STRATEGY [40 CFR 146.82(a)(7), (a)(8), (10), (11), (12) 146.86, 146.87]

Milestone's permit **Section 3** describes the engineering design details, and **Section 4** includes operational strategies employed during the planning of the Midland CCS #2 Injection Well proposed by Milestone.

4.1 Injection Well Operating Strategy

Injection is planned for an average of 1.0 MMt/yr of CO_2, which will remain in the supercritical state through the entirety of the project. **Table 4-1** summarizes the maximum wellhead and bottomhole pressures. See relevant modeling figures in **Section 2** for additional information on expected pressure increases. After the commissioning period is complete (**Section 4.2**), the injection strategy is to inject into the openhole portion of the Midland CCS #2 Well for 12 years at 54,526,360.6 standard cubic feet per day (SCF/D). This gas volume and rate is equivalent to 1 million metric tons of CO_2 per year.

Milestone proposes the project be limited to 1 million metric tons of CO_2 per year. However, given that there may be days with downtime due to maintenance or monitoring activities, the daily injection rate may be variable. The maximum allowable rate should be slightly higher than the modeled rate of 54.5 MMscf/d. Milestone proposes a maximum rate of 60 MMscf/d assuming the maximum allowable surface and bottomhole pressures are not exceeded, and the annular pressure is increased to compensate for the increase in tubing pressure. This rate aligns with specifications of the tubing.

Bottomhole pressure will not exceed 90% of the fracture pressure of the injection interval, which will limit surface injection pressure. The anticipated bottomhole injection pressure (BHIP), frac gradient with 90% safety factor and injection rate plot over time is 7,875 psi as shown in **Table 4-1**.

Values in **Table 4-1** are the proposed operating parameters for the Midland CCS #2 injection well. Average pressure values are likely to be adjusted once the test well is drilled. Maximum pressure and rate values are not expected to change substantially since they are linked to the fracture gradient and pipe size constraints. However, the fracture gradient may change pending pre-operational testing results.

Milestone will perform any manufacturer recommended maintenance to coincide with the schedule of monitoring activities in **Section 6** to limit downtime.

Table 4-1: Proposed Operational Procedures

Parameters / Conditions	Limit or Permitted Value
Maximum Injection Pressure	
Surface (Wellhead)	4000 psi
Bottomhole- Top of Siluro-Devonian (90% of Frac Gradient)	7,875 psi
Average Injection Pressure	
Surface (Wellhead)	2,949 psi
Bottomhole	7,311 psi
Maximum Injection Rate	3,086 tonnes/day, 60 MMscf/d
Average Injection Rate	2,740 tonnes/day, 54.5 MMscf/d
Maximum Injection Mass	1 MMt (per year)
Average Injection Mass	1 MMt (per year)
Average Annulus Pressure	3,049 psi
Annulus Pressure / Tubing Differential	+100 psi

Table 4-2: Injection Intervals

Completion Unit	Completion Timing	Injection Duration (years)	Top of Interval (TVD ft)	Bottom of Interval (TVD ft)	Net Pay (ft)
Siluro-Devonian and Ellenburger	Year 2027	12	12,200	13,849	1,649

4.2 Commissioning Period

Milestone will not immediately achieve full injection rates. There will be a 90-day commissioning period where rates will be increased gradually at approximately 4.5 MMSCFD per week. This will be performed to:

- Test the surface infrastructure gradually
- Alleviate any initial relative permeability effects in the reservoir
- Fully understand pressure response at different rates.

The first monitoring report, submitted to the UIC Director, will include data on the commissioning period in addition to other normal monitoring data.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment F: Testing and Monitoring Plan

[40 CFR §146.90]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Fiberoptic Design Prepared by:

ESG Solutions

10815 Woodedge Drive

Houston, Texas 77070

Earthquake Magnitude Study Prepared by

Instrument Software Technologies, Inc (ISTI)

5 Case Street

Saratoga Springs NY 12866

Updated 16 April 2025

Table of Contents

List of Tables

List of Figures

6.0 TESTING AND MONITORING PLAN [146.82(a)(15), 40 CFR 146.90]

This Testing and Monitoring Plan describes how Milestone will monitor the Injection Well (Well), pursuant to [40 CFR § 146.90]. In addition to demonstrating that the Injection Well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the injection unit to support AoR re-evaluations and a non-endangerment demonstration. Additional applicable testing methods may be added to reconcile observed and actual results.

Results of the testing and monitoring activities described herein may trigger action according to the AoR Re-Evaluation Criteria (**Section 2**) and or the Emergency and Remedial Response Plan (**Section 10**).

6.1 Overall Strategy and Approach for Testing and Monitoring

The operating plans for the proposed Well will include a robust testing and monitoring program. Milestone will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR § 146.91. This section discusses the key details of this program.

Milestone will access the site via a lease road. The injection well facility is adjacent to an existing Milestone class II injection facility that handles oilfield liquid waste. Milestone does not anticipate any barriers to, or issues with, accessing the site to conduct monitoring activities.

6.1.1 Quality Assurance Procedures [146.93]

Section 13, Appendix C reflects Milestone's QASP for testing and monitoring activities pursuant to the requirements in 40 CFR 146.90(k). This performance-based plan sets forth the procedures and guidelines the EPA will use in evaluating the technical performance of Milestone. Procedures for measurement of various sections of this document are found in **Section 13 Appendix C – QASP**.

6.1.2 Reporting Requirement [146.91]

Per the requirement of 40 CFR 146.91, Milestone will provide semi-annual reports to the UIC Director containing the following:

1. Any changes to the physical, chemical and other relevant characteristics of the CO_2 stream from what has been described in the proposed operating data (**CO_2 Specs - Section 3**).
2. Monthly average, maximum and minimum values of injection pressure, flow rate and volume, and annular pressure.
3. Description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit.
4. Description of any event which triggers a shut-off device and the response taken plus any effect it had on the volume or mass of CO_2 injected.
5. Monthly volume and/or mass of the CO_2 stream injected over the reporting period and the volume injected cumulatively over the life of the project and reporting period.
6. Monthly annulus fluid volume added.
7. Results of any monitoring as described in this section or under 40 CFR 146.90.

In addition, reports will be submitted within thirty (30) days after the following events:

1. Periodic tests of mechanical integrity.
2. Any well workover.
3. Any other test of the injection well conducted if required by the Director.

Reports will be submitted to the Director, within 24 hours of the following:

1. Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW.
2. Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.
3. Any triggering of a shut-off system, either downhole or at the surface.
4. Any failure to maintain mechanical integrity.
5. Any anomalous release of carbon dioxide to the atmosphere outside of normal engineering tolerances for operations.

Notification will be made to the UIC Program Director, in writing, 30 days in advance of:

1. Any planned workover.
2. Any planned stimulation activities as defined in **Section 7.**
3. Any other planned non-routine test of the injection well.

All reports, submittals and notifications will be submitted to EPA UIC Program Director and or relevant state agencies in compliance with all applicable regulations. All records will be retained by Milestone throughout the life of the project and for ten (10) years following site closure. Data on the nature and composition of all injected fluids collected will be retained as well for ten (10) years after site closure. The records will be delivered to the Director after the retention period if required by the Director. Monitoring data as described in this Section will be retained for ten (10) years after it is collected. Well plugging reports, post-injection site care data and the site closure report itself will be retained for ten (10) years following site closure. Any records that the EPA UIC Program Director requires will be retained longer than 10 years after site closure.

6.1.3 Testing Plan Review and Updates [146.90 (j) (1) (2) (3)]

This testing and monitoring plan will be reviewed and updated to incorporate monitoring data collected as described at least once every five (5) years. An amended testing and monitoring plan will also be submitted within one year of an area of review re-evaluation, following any significant changes to the facility such as the addition of monitoring wells or newly permitted injection wells within the area of review; or as required by the Director (re-evaluation criteria found in **Section 2**).

6.2 Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b),146.90(b)]

6.2.1 Continuous Monitoring of Injection Wells

Milestone will install and use continuous measurement devices to monitor injection pressure, rate, and volume, the pressure on the annulus between the tubing and the long string casing, the annulus fluid volume added, and the temperature of the CO_2 stream, as required under 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b) (**Table 6-1**) within the Injection Wells.

Data interfaces will be created for equipment that is not linked directly to the SCADA system, to 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 malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside described tolerances which is generally 90% of fracture gradient, maximum permitted wellhead pressures, and changes in annular pressure and fluid volumes. The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the project will be stored in a central database to provide support for AoR reviews, QA programs, and reporting.

Table 6-1. Sampling devices, locations, and frequencies for continuous monitoring in Injection Wells

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface	5 seconds	5 minutes
Bottom Hole pressure	Pressure Gauges	Wellbore	5 seconds	5 minutes
Injection rate	Metering Device	Wellhead	5 seconds	5 minutes
Injectate density	Metering Device	Wellhead	5 seconds	5 minutes
Injection volume	Calculated from rate and density	N/A	N/A	N/A
Annular pressure	Pressure Guage	Wellhead	5 seconds	5 minutes
Annulus fluid volume	Volume Added Meter	Wellhead	5 seconds	5 minutes
CO_2 stream temperature	Metering Device /WPL	Wellhead	5 seconds	5 minutes
CO_2 stream temperature	DTS	Wellbore	5 minutes	See **Table 6-5**
Induced Seismicity	DAS and Near Surface Geophones	Wellbore and Near Surface	5 milliseconds for NSSW; Fiber See **Table 6-5**	5 milliseconds for NSSW; Fiber See **Table 6-5**
Strain	DAS	Wellbore	2 seconds	See **Table 6-5**
Gas Composition	Gas Analyzer	Pipeline	5 seconds	5 minutes

6.2.1.1 Well Temperature

Wellbore and the surrounding formation temperatures will be measured using Distributed Temperature Sensing (DTS) data acquired through a fiber optic cable, embedded in the cemented annulus behind the long string casing. The fiber optic cable location in the injection well and In-zone Monitoring well is illustrated in the wellbore diagrams in **Section 3**. In addition to DTS, Low-Frequency Distributed Acoustic Sensing (LF-DAS) data will also be used to indirectly measure the wellbore temperature and any fluid movement behind the casing as fiber is sensitive to both temperature and pressure fluctuations in the wellbore. For specialized data such as fiber optic DAS and DTS, the project will have additional support from the provider of the selected technologies to perform QC and verification of the data as well as calibration of the systems as needed. The wellhead pressure logger (WPL) and Coriolis Meter will also continuously measure the temperature at surface and can be used as a backup in case the DTS fails. DTS and DAS data recording practices will be discussed further in the fiber optic section.

6.2.1.2 Injection Rate, Temperature, Density and Volume

At the injection well, a metering device such as a coriolis mass flowmeter will be utilized to measure injection rate, injectate temperature, injectate density, and energy inputs. Volume will be calculated from the density and rate. The meter will be placed at a location based on manufacturer specifications immediately upstream of the injector wellhead and downstream of any capture facilities. The meter will be calibrated to manufacturer specifications

6.2.1.3 Injection Pressure

Injection pressure will be monitored using wellhead and downhole pressure gauges. The injection well will be equipped with permanent downhole gauges above the packer (illustrated in **Section 3**) that will continuously monitor the injection pressure and annular pressure at that depth and transmit the data via a tubing encapsulated conductor (TEC) cable. The pressure gauges will continually monitor the injection pressure to ensure that it does not exceed 90% of the fracture gradient as required by 40 CFR 146.88(a). Additionally, the Well will be equipped with a wellhead surface pressure logger to ensure the surface pressure remains below allowable wellhead pressures.

6.2.1.4 Annular Pressure and Volume

The annular pressure between the tubing and the injection casing strings and the annular fluid volumes also will be monitored on a continuous basis at gauges located in the wellhead and above the packer. The pressure gauge on the annulus will be tied into the SCADA system and set to alarm if pressure or volumes move outside set tolerances.

6.2.1.5 Positive Annular Pressure

Per 40 CFR 146.88(c), Milestone will maintain pressure in the annulus of at least 100 psi greater than the injection pressure. Milestone 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 compressed non-corrosive fluid or gas and it will be tied into the SCADA alarms if pressure drops below tolerances.

6.2.1.6 Gas Composition

Gas stream composition will be measured continuously upstream of the wellhead but after the last stage of compression in the pipeline. Milestone will employ a continuous gas analyzer device that meets the temperature, pressure and rate requirements of the project. This is discussed further in permit **Section 6.12**.

6.3 Testing and Monitoring Techniques QA/QC [40 CFR 146.90(k)]

6.3.1 Casing and Tubing Inspection Tools

For mechanical integrity evaluation, Milestone will use Ultrasonic Casing Inspection Tool (USIT), Electromagnetic Pipe Examiner (EM Flux tool), Cement Bond Logs (CBL) and a MultiFinger caliper that evaluates the conditions of the tubulars and casing in the well and provides information about thickness, ovality, ruptures, potential corrosion, etc. Inner diameter restrictions of tubing will be considered when selecting logging tools. More information about these casing inspection tools may be located in **Section 13 – Appendix C, the QASP**.

6.3.2 Pulsed-Neutron Logging

Pulsed-neutron logging is considered a proven technique to detect gas saturation in reservoirs. Advances in technology have improved the accuracy of the tool to track the movement of the CO_2 plumes in the reservoir and evaluate flow conformance. **Figure 6-1** illustrates time-lapse PNX log response in an example injection well after CO_2 injection.

The red area indicates CO_2 replacing formation brine in the near wellbore region. It can be observed on the apparent neutron porosity (TNPH), the Sigma (SIGM) and especially on the fast neutron cross section (FNXS) log. Since the neutron log primarily responds to hydrogen, found in water, the gas displacing the water alters all these logs.

In formations with CO_2, or any gas, there is a reduction in the neutron capture rate because gas has a lower neutron absorption cross-section than water or oil. This results in fewer interactions with neutrons, and due to a change in spectrum the tool can detect the lower neutron capture response associated with gas as represented by the FNXS and Sigma log. (**Figure 6-1**)

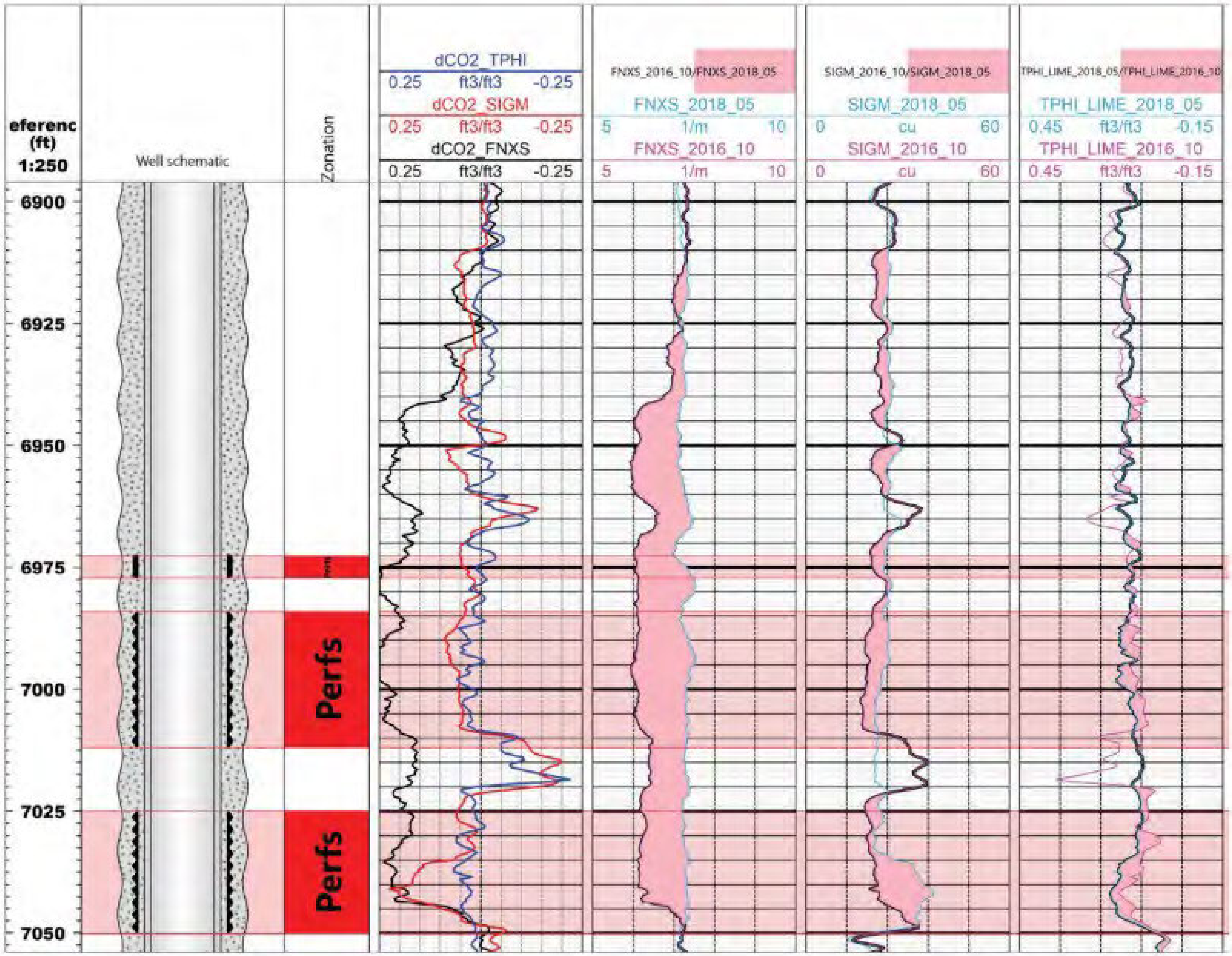


Figure 6-1: Time lapse PNX log response (Laronga et al., 2023

6.4 Corrosion Monitoring [40 CFR 146.90 (c)]

To meet the requirements of [40 CFR 146.90(c)], Milestone will monitor the tubing and casing materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. Data will be reported semi-annually as part of the report described in **Section 6.1.2**

6.4.1 Monitoring Location and Frequency

Milestone will monitor corrosion using a corrosion coupon method and collect samples according to the description below. Milestone will examine the coupons quarterly.

Milestone will measure temperature and strain on the fiber continuously using the DAS and DTS data acquired through the fiber installed in the cemented annulus behind the long string casing of the injection well. 40 CFR 146.89(c) requires that at least once per year the operator will run a temperature, noise or an oxygen activation log. The results of the DAS and DTS data will be interpreted, collated, and submitted to the EPA UIC Director at least twice per year (Semi-annually as part of the report in **Section 6.1.2**) in lieu of running one of the aforementioned wireline logs.

Milestone will perform mechanical integrity logs (i.e., USIT, EM, CBL, Multifinger Caliper) every five (5) years. Inner diameter restrictions of tubing will be considered when selecting logging tools. If continuous well measurements indicate well integrity has been compromised, and the continuously recorded data cannot be used to determine the cause, Milestone will run wireline logs to further evaluate the cause of the mechanical integrity event in consultation with the EPA UIC Director.

6.4.2 Coupon Sampling Methods

Corrosion coupons, made of the same material as the production casing, wellhead and the injection tubing will be placed in the CO_2 injection pipeline in a flow through pipe arrangement or testing loop downstream of all compression, dehydration, and pumping equipment to ensure the coupons are exposed to representative downhole conditions. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards for evaluating corrosion tests. When the coupons are removed, they will be inspected visually for any signs of corrosion, including 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. Data will be reported semi-annually.

Coupon initial baseline and periodic measurements will follow the recommendations of AMPP NACE SP0775-2023 (included in **Section 14 References** and **Section 13 Appendix C - QASP**). A brief summary of those requirements is presented here.

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. Grinding operations will be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon. Coupons will be prepared by smooth grinding with 120 grit paper, by tumbling with loose grit, or blasting with abrasive blasting material. A consistent finish will be obtained by blasting with glass beads. All abrasives will be free of metallic particles. A permanent serial number will be etched or stamped on each coupon. Milestone will machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data. Milestone 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.

6.5 Above Confining Zone Water Monitoring [40 CFR 146.90 (d); 40 CFR 146.82(a)(6)]

Milestone will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of [40 CFR 146.90(d)]. The purpose of the groundwater monitoring is to detect potential changes that may result from fluid leakage out of the injection unit.

6.5.1 Location of In-zone Monitoring Wells

Milestone will construct one (1) In-zone monitoring well near the edge of the projected AoR and oil and gas wells of interest such as JRS Farms 22. Details on these active oil and gas wells may be located within permit **Section 1 and Section 2**. Out of an abundance of caution, this will allow Milestone to monitor plume and pressure changes in proximity to active oil and gas wells even though the oil and gas wells are not within the AoR. Monitoring well locations are illustrated in **Figure 6-2**.

6.5.2 Location of USDW Monitoring Wells

Milestone will construct five (5) water wells that are co-located with near surface seismometers. The water-seismometer wells will be drilled in a grid pattern around the AoR with four (4) on the edges and one (1) in the approximate center.

Since there is a substantial depth difference between the top of the aquifer and the USDW depth, Milestone will also construct one (1) USDW monitoring well, Wellbore Diagram is found in **Section 3**. In order to maximize detection, the Midland NSSW #5 will be located in the updip direction for the Edwards-Trinity (Plateau) aquifer (NW). Meanwhile, the Midland USDW #2 will be located in the updip direction of the Dockum aquifer (SW). More about aquifer structure is described in **Section 1.4.**

Monitoring well locations are illustrated in **Figure 6-2**.

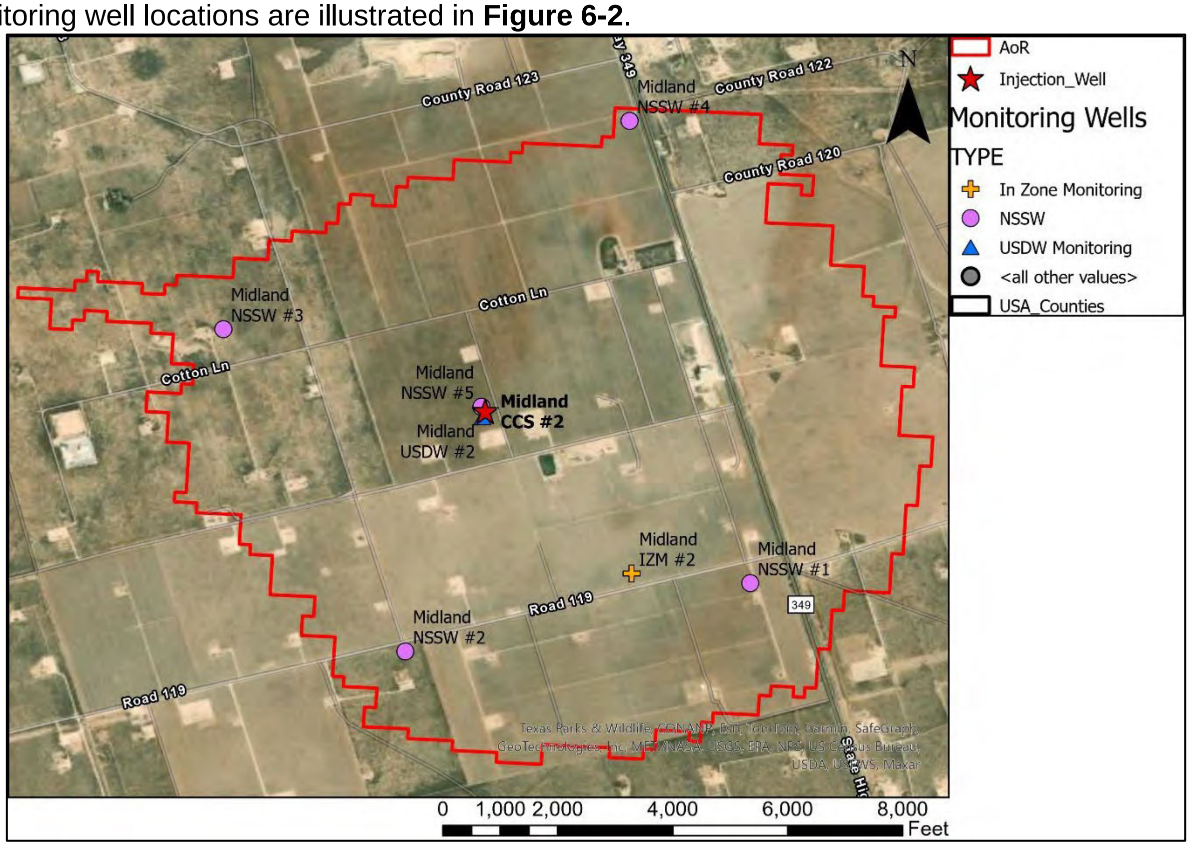


Figure 6-2: Map of Monitoring wells in relation to Injection Wells

6.5.3 USDW and Above Zone Water Quality Monitoring

All samples in this section will be having a testing schedule outlined in **Table 6-2** and a testing matrix found in **Table 6-3**.

Before drilling, and again before commencing injection, per 40 CFR 146.82(a)(6), Milestone will acquire baseline water samples from five (5) wells that are co-located with near-surface seismometers. The water well's locations will be selected to encompass the area of review. All aquifers within the area of review will be sampled, in this case Dockum and Edwards-Trinity (Plateau) aquifers. Water samples will be taken from the same near-surface seismometer/water wells as a baseline, then once quarterly during the injection phase of the project. Seismometer/water-sampling wells will have electrical probes installed for continuous monitoring of alkalinity, pH and electrical conductivity (EC). These probes will be used to monitor potential contamination of the Edwards-Trinity (Plateau) aquifer which is closer to the surface than the deepest USDW. A schematic, not to scale, of the seismometer/water well design can be found at the end of **Section 3.**

Within the USDW monitoring wells, electrical probes will be used for continuous monitoring of alkalinity, pH and electrical conductivity (EC). These probes will be used to monitor potential contamination of the lowermost USDW, the Dockum aquifer. Milestone will acquire water samples from the USDW monitoring wells before injection begins as a baseline then at least once (1) quarterly during the injection phase of the project to monitor for changes in brine chemistry. The number of monitoring locations and frequency of sampling is detailed in **Table 6-2**. A schematic of the USDW monitoring well can be found in **Section 3**.

Milestone will install a U-tube system on offset In-zone Monitor wells (IZM Wells) to monitor brine chemistry and gas concentration in the first permeable zone above the Top Seal. The monitored formation is expected to fall within the Pennsylvanian section below the Wolfcamp but above the top-seal, probably the Strawn formation. Well schematic for IZM Wells may be located within **Section 3**. Milestone will acquire a baseline water sample before injection begins and then once (1) every year during the injection phase of the project.

A decrease or increase in value beyond seasonal variation and/or the measurement accuracy could be an indication of potential CO_2 entering the hydrosphere and will be further investigated. Values that spur investigation are found in **Section 6.5.6.**

Table 6-2: Monitoring of groundwater quality and geochemical changes above the confining zone

Target Formation	Approximate Depth	Monitoring Activity	Monitoring Location(s)	Water Sample Frequency
Edwards-Trinity (Plateau)	300 ft	Sampling, Probes	5	Baseline, then Quarterly
Lowermost USDW (Dockum base)	1250 ft	Sampling, Probes	1	Baseline, then Quarterly
Pennsylvanian	11000 ft	Sampling (U-tube)	1	Baseline, then Annual

6.5.4 Discrete Chemistry and Isotope Analysis

Water samples taken during and before the injection phase of the project will be tested for the chemistry and isotope analysis contained in **Table 6-3**. Post injection, water testing will be conducted in exactly the same manner, but it is duplicated for ease of reading in **Section 9**.

Table 6-3: Summary of analytical and field parameters for groundwater samples

Parameter	Frequency	Analytical Methods
Dissolved CO_2	Annual	Coulometric Titration, ASTM D513-11
Total dissolved solids	Annual	Gravimetry, APHA 2540C
pH (field)	Annual	EPA 150.1
Specific conductivity (SC) (field)	Annual	APHA 2510
Temperature	Annual	Thermocouple
Water Density	Annual	Oscillating body method
Cations – Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	Annual	ICP-MS, EPA Method 6020
Cations – Ca, Fe, K, Mg, Na and Si	Annual	ICP-OES, EPA Method 6010B
Anions – Br, Cl, F, NO_3, HCO_3 and SO_4	Annual	Ion Chromatography, EPA Method 300.0
δ 2H and δ 18O isotope analysis	Annual	Isotope ratio mass spectrometry
δ13 C dissolved inorganic carbon	Annual	Isotope ratio mass spectrometry
Alkalinity	Annual	APHA 2320B

6.5.5 Sampling and Analytical Methods

Fluid samples in NSSW monitoring wells and the USDW monitoring well will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone, via wireline or slickline, and the rate of sample collection should not exceed the rate at which the well was purged.

For In-zone Monitoring well, a permanent U-tube sampling system will be installed within the annulus and used to sample the brine above the Top Seal.

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

6.5.6 Values that May Indicate Leakage

Trends that may indicate fluid leakage and will trigger an investigation, include:

- Major change in TDS, minus seasonal variation
- Major change in signature of major cations and anions, minus seasonal variation
- Major change in carbon dioxide concentration, minus seasonal variation
- Major change in Carbon 13 and Oxygen 18 isotopic values
- Major change in pH
- Major increase in concentration of injectate impurities.

6.5.7 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

6.5.8 Quality Assurance and Surveillance Measures [40 CFR 146.90(k)]

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

6.6 External Mechanical Integrity Testing [40 CFR 146.89, 40 CFR 146.90(e)]

Continuous DAS and fiber strain data will be utilized to verify external mechanical integrity. Results of DAS and strain data will be interpreted, collated and submitted to the director at least once per year. DAS/strain data will be submitted in lieu of wireline logging. Wireline noise and temperature logging or oxygen activation logs will not be conducted unless a probable mechanical integrity leak is detected. The results of DAS/strain will demonstrate the absence of significant fluid movement into the USDW, and no significant leak in casing, tubing or packer as required by 40 CFR 146.89(a)(c) and 40 CFR 146.90(e).

Additionally, Milestone will utilize USIT, CIT, CBL and EM tools (casing inspection tools) at least once every five (5) years during the injection phase to verify mechanical integrity pursuant to 40 CFR 146.89(d). Milestone will conduct casing inspection logging on both Injection Wells and In-Zone Monitoring Wells but not USDW or NSSW monitoring wells.

Additionally Internal mechanical integrity of the injection wells will be demonstrated via a tubing-casing annulus pressure test prior to injection and at least once every five (5) years. Continuous annular pressure monitoring to satisfy 40 CFR 146.89(b) is described in **Section 6.2**.

In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, Milestone will apply methods and standards generally accepted in the industry. When Milestone reports the results of mechanical integrity tests to the Director, it will include a description of the test(s) and the method(s) used when making evaluations per 40 CFR 146.89(f).

6.7 Pressure Falloff Testing [40 CFR 146.90 (f)]

Milestone will perform pressure falloff tests during the injection phase as described below to meet the requirements of [40 CFR 146.90(f)]. A pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every five (5) years thereafter to demonstrate storage reservoir injectivity. The results of these tests will be reported to the UIC Division on Form UIC-5 within 30 days of the test. These tests will be used to measure formation properties near the injection well and to monitor for any changes in the near-well bore environment that may impact injectivity and increase pressures.

6.7.1 Testing Method

Prior to beginning the pressure falloff test, injection rate and pressure will be maintained as constant as possible, while continuously recorded. Upon shutting in the well, pressure measurements will be taken continuously through the use of at least two bottomhole pressure gauges, with one serving as a backup and for verification in cases of questionable data quality (see **Section 3** for location of bottomhole permanent pressure gauges). The falloff period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

6.7.2 Analytical Methods

Standard diagnostic log-log and semi-log plots will be generated with observed pressure changes and/or pressure derivative plots. The purpose of these tests is to determine specific near-wellbore conditions, such as well skin, the prevailing flow-regimes and hydraulic property and boundary conditions. Comparison of pressure falloff tests prior to beginning injection operations with those performed subsequently can indicate whether significant changes in the well or reservoir conditions have occurred. Analysis will consider the effects of two-phase flow effects, and parameters determined from the falloff test will be compared to those used in the site computational modeling and AoR determination. Any significant changes in reservoir properties may result in a reevaluation of the AoR (see **Section 2-AoR Re-Evaluation Criteria**). Results of the pressure fall of test will be reported to the UIC Division within 30 days of the test.

6.7.3 Quality Assurance/Control

All field equipment will be inspected and tested prior to use. Pressure gauges used in the falloff test will be calibrated in accordance with manufacturers' recommendations and calibration certificates will be provided with the test results. The use of the second bottom-hole pressure gauge will further provide validation of the test results.

6.8 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.90 (g)]

Milestone will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of [40 CFR 146.90(g)]. A summary of direct and indirect methods is found in **Table 6-4**.

6.8.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, the Injection Well and the In-zone Monitoring (IZM) well will be equipped with fiber optic cable cemented behind the annulus of the casing, (**Section 3** - Well Schematics). The In-zone monitoring well will additionally be equipped with U-tube sampling systems. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, which provides sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

The fiber optic sensing system installed within the Injection Wells will be used to acquire continuous high-resolution temperature (DTS) and acoustic data (DAS). The fiber optic sensing system in the Injection well will not cover the injection zone, only the Top Seal. Having the fiber along the Top Seal allows monitoring the integrity of the seal and CO_2 leak behind the casing.

The fiber optic system in the IZM wells will be used to acquire DTS and DAS data prior to injection as a baseline survey and yearly once (1) for the first two (2) years and every six (6) months from 3rd year onwards. DTS and DAS data from the IZM wells will be used to track CO_2 plume and pressure front when it migrates to the IZM wells. This data provides both horizontal extent and vertical extent of the plume at the fiber well (see **Section 6.9** Fiber Optic Monitoring Section for more information).

Pulse Neutron Log (PNLs) of the injection and monitoring wells will also be performed at least once every five (5) years to demonstrate that fluids are not moving beyond the sealing formations. Pre-operational baseline PNL data will be collected in the Injection and In-zone Monitoring wells. These time-lapse saturation data will be used to monitor for potential CO_2 in the formation directly above the storage reservoir, utilizing data from both the Injection wells and In-Zone Monitoring wells as an assurance-monitoring technique.

Milestone will take injection zone fluid samples from IZM wells utilizing two (2) separate U-tube sampling systems that are installed within the annulus. The U-tube sampling systems will be designed to take samples from the Siluro-Devonian interval and the Ellenburger interval, both of which are within the injection interval. Fluid samples from the IZM wells will be taken prior to the start of injection and at least once (1) annually during the injection period.

Fluid samples from injection wells will only be taken once (1) every five (5) years when the downhole valve is removed for MIT testing. Fluid sample laboratory testing program is summarized in **Table 6-3** and In-zone samples testing will use identical procedures to Above-zone fluid samples.

Table 6-4: Summary of Direct and Indirect Plume and Pressure Front Monitoring

Monitoring Activity	Property to Measure	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
DAS/DSS/DTS	CO_2 Leakage	Injection Well	Wellbore	Continuous[1]
DAS/DSS	Pressure and Plume Front	In-zone Monitoring Well	Wellbore	Before Injection, then yearly for the first two years and then every 6 months
Pressure Gauges	BH Injection Pressure, BH Annular Pressure	Injection Well	Wellbore	Continuous[1]
Pulse Neutron	CO_2 Saturation (Plume front)	Injection Well, In-zone Monitor Well	Wellbore	Before Injection, then every 5 years
Water Sampling	Plume Front; CO_2 Leakage	Injection Well, In-zone Monitor Well	Wellbore	Monitor Well - 1 Year prior to Injection then Annually; Every 5 years in Injection Well
INDIRECT PLUME MONITORING				
Microseismic Monitoring	Pressure Front (Mode 2 Deformation)	Wellbores DAS, Sparse Near-Surface Array	Wellbore Locations, Estimated edge of the Area of Review	NSSW Wells – Continuous at 5 Milliseconds; DAS see above DAS entry
Surface Electromagnetic Survey (CSEM)	Plume Front (Conductivity)	Surface EM Array	Estimated Area of Review (AoR) at that time to a maximum of 9 sq. mi area	Before Injection, 1 year after injection starts, then every 5 years
PASSIVE SEISMICITY MONITORING				
Passive Seismicity	Earthquakes	5 Surface Seismometers	Operator owned stations within AoR; TexNet + USGS	Continuous[1] from 6 months prior to injection

[1] Continuous is defined more precisely in **Table 6-1** and in **Table 6-5**

6.8.2 Indirect Monitoring Methods

Indirect monitoring methods will track the extent of the CO_2 plume front and pressure front within the storage reservoir. The fractured nature of the injection interval renders traditional 4D seismic and Vertical Seismic Profiles (VSP) methods ineffective. Therefore, Milestone will forgo more traditional 4D seismic methods in lieu of methods more suitable for fractured carbonates. Microseismic monitoring surveys and Electromagnetic surveys will be utilized to determine pressure and plume front respectively.

At the conclusion of the injection phase of the project, the monitoring program will permit an assessment of the long-term containment and stability of the injected CO_2 within the storage complex. This assessment is required to secure a certificate of project completion from EPA. To this end, monitoring of the storage complex will continue following the cessation of CO_2 injection until it can be established that the injected CO_2 plume is stable.

6.8.2.1 Microseismic Surveys

Milestone will conduct a microseismic survey at the start of injection for a maximum duration of three (3) months and then subsequently once every five (5) years for a maximum duration of one (1) month. Milestone will utilize existing near-surface seismometers and cemented DAS during the surveys. Milestone may also utilize additional temporary surface stations, and a temporary lowered vertical geophone array in one or both of the monitoring wells at the time of the survey if existing permanent equipment is not sufficient to detect and locate events. Milestone does not expect to see microseismic events induced from the injection wells at the start of injection. However, Milestone does expect to see events from offset oil and gas operations such as hydraulic fracturing of the overlying Wolfcamp and Spraberry formations (data supporting this is found **Section 6.10.3**). See **Section 6.9 and 6.10** for additional information on fiber optic monitoring and passive seismicity respectively.

6.8.2.2 Controlled Source Electromagnetic Surveys

Controlled-source electromagnetic (CSEM) method is a proven geophysical technique for exploration, production and monitoring of oil and gas resources and natural mineral deposits. In this remotely sensing method, usually a grounded electric bipole (via two electrodes) energizes the subsurface with an alternative current containing a variety of spectrum of frequency to produce time-varying electric and magnetic fields that can be measured on the earth's surface. The measured electromagnetic (EM) data can be processed and interpreted to infer the information about the electric conductivity or its reciprocal resistivity of the subsurface (**Figure 6-3**).

According to Archie's law (G. Archie, 1942), the electrical resistivity of formation rocks is highly sensitive to changes in water/brine saturation (Sw). Consequently, this high sensitivity to Sw in a reservoir can be exploited by EM techniques. Since electric resistivity is primarily a function of pore fluid rather than rock matrix, EM methods may have higher sensitivity in some cases than other geophysical methods, for example, the seismic method. EM methods have been shown to be effective in fractured reservoirs as they are often employed to track hydraulic fracturing of low porosity, low permeability formations.

When CO_2 is injected to the reservoir formation, assuming no hydrocarbons are present, the water saturation S_W is directly related to the injected CO_2 saturation by $S_W = 1 - S_{CO2}$. In terms of its EM effects, as illustrated in **Figure 6-3**, there are two consequences: increase the volume of the CO_2 plume and change the CO_2 resistivity. For example, if the CO_2 saturation is 0.05 (or 5%), it will result in 10.8% change in CO_2 resistivity, compared with the virgin formation resistivity ρ_f. For a CO_2 saturation of 0.2 (or 20%), the resistivity will be changed by 56.3%. Indeed, EM response shows higher sensitivity to CO_2 saturation.

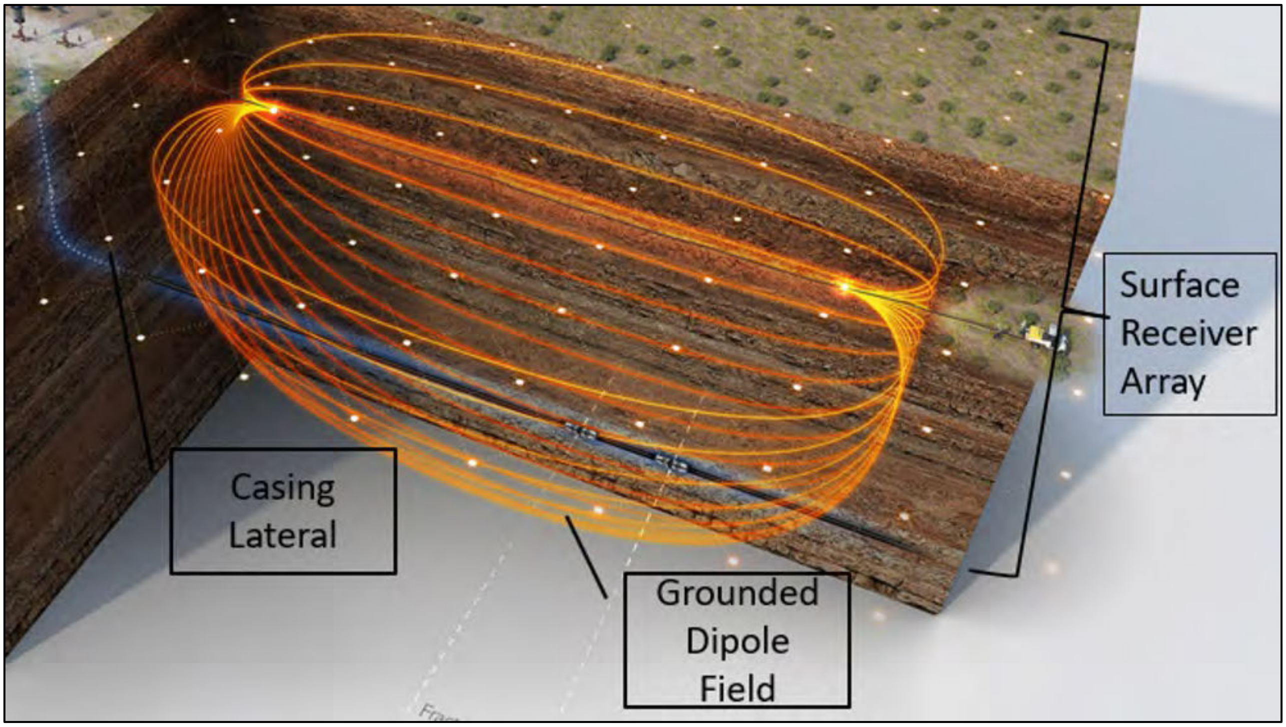


Figure 6-3: Schematic Example of EM survey
CSEM survey of a horizontal hydraulically fractured well showing the detectors, transmitters and electric field produced during a CSEM survey

Two orthogonal transmitter electrodes connected by a cable, are deployed on the surface, providing up to 200 kW power to energize the subsurface. To effectively suppress the noise and increase signal-to-noise ratio, a unique pseudorandom current waveform is injected into the ground. A set of sensitive receivers are distributed on the survey area (the yellow dots) on a regular grid and can register the two orthogonal components of the electric field in both time and frequency domains (**Figure 6-3**). The scattered electric fields, which are the difference between the post-injection and pre-injection measurements, are sensitive to the conductivity or resistivity change in the injection zone. Therefore, by continuously measuring these field changes with time, the injected fluid or CO_2 movement could be monitored through 3D EM forward modeling and inversion.

Tx-Rx layout is displayed in **Figure 6-4**, where about 300 receivers are deployed in a circle of radius of 2,000 ft around the injection well. Two orthogonal electric components will be picked up by these sensors, and the Rx spacing is about 300 ft. One of the transmitter electrodes is positioned close to the cased injection well, hoping enough EM energy will reach out to the injection zone of interest at depth of 12-14,000 ft. The other transmitter electrode will be put 3,600 ft away from the injection well. We expect that using this Tx-Rx layout will cover the injection scenarios within 10 years of operation. Receiver density and spacing will be adjusted as the plume model and front evolves over time.

Milestone will conduct a CSEM survey once before injection, then once at year one (1) after injection begins and finally subsequently once every five (5) years from the start of injection, until injection terminates. Each survey will utilize static and variable injection rates. Milestone will ramp up injection rates over a period of 12 hours while measuring the CSEM survey then measure for 12 hours of sustained constant rate. Measurements will be compared to petrel simulations of CO_2 plumes.

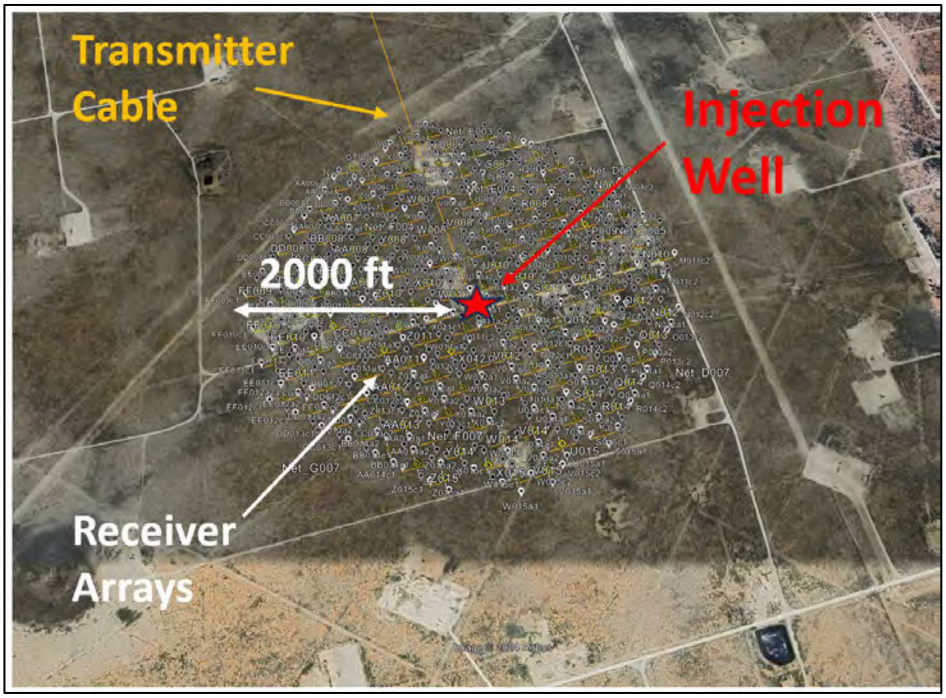


Figure 6-4: Schematic Example of CSEM Survey Transmitter and Receiver spacing

6.8.2.3 Ineffectiveness of Active Seismic Methods

Milestone undertook forward modeling to test the negative hypothesis: *CO_2 injection would not alter the 3D seismic response*. Using Hampson Russel® Software, Milestone conducted fluid substitution using the Pegasus Field Unit #20-12 log (API#: 42-461-32586). Milestone simulated 1) initial conditions, where the injection interval is filled with reservoir brine; and, 2) fully saturated with injectate (60% CO_2 saturation) and displayed them side-by-side to compare the endmembers (**Figure 6-6**).

The fluid substitution forward model was generated using a wavelet that was extracted from the 2D seismic data. It has a frequency content of 13 Hz to 37 Hz (**Figure 6-5**) in the deep stratigraphic section of Fusselman and Ellenburger. Note that the maximum amplitude in the power spectrum occurs at 20 Hz, and that the amplitudes diminish from there to 37 Hz. It was important to use this wavelet, as it represents the actual frequency distribution of the recorded seismic data in the area, rather than a hypothetical frequency distribution. The results were compared against a theoretical wavelet with 5-50 Hz and uniform frequency content as a baseline, but the result was the same.

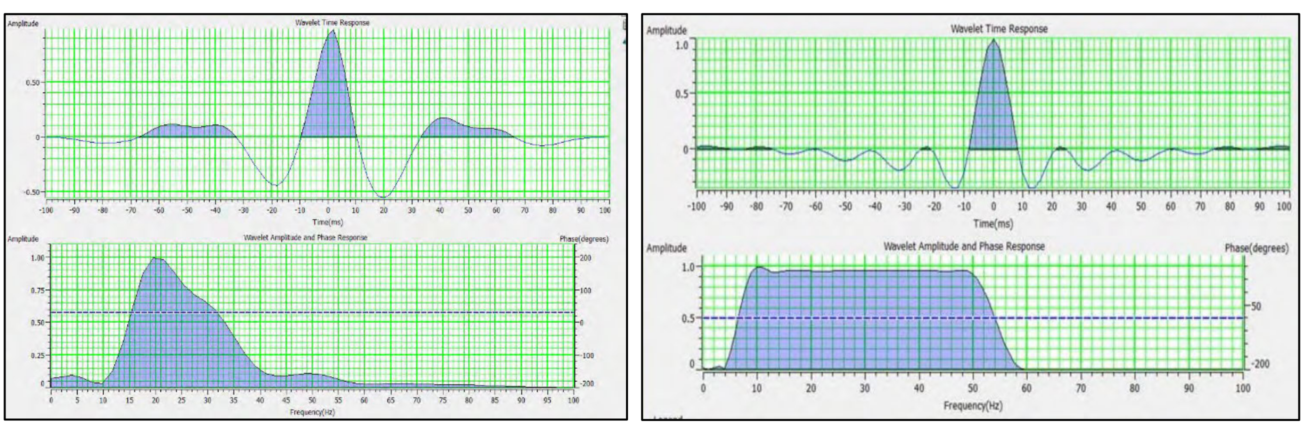


Figure 6-5: Wavelet and Power Spectrum Extracted from Seismic Dataset

(Left) is the actual seismic data from the 2D lines in the area. (Right) is the theoretical wavelet with 5-50hz

The basic data used in the generation of the models were:

A. Ellenburger
   a. Mineralogy: 90% Dolomite, 10% Calcite
   b. Kdry (Bulk Modulus): 50 GPa
   c. Threshhold Porosity: 0.5%
   d. Fluid Saturation Post Injection: 60% CO_2 + 40% Brine
   e. CO_2 Density: 0.8 g/cc
   f. Bulk Modulus CO_2 : 0.5 GPa

B. Siluro-Devonian
   a. Mineralogy: 40% Quartz, 60% Calcite
   b. Kdry (Bulk Modulus): 29 GPa
   c. Threshhold Porosity: 0.5%
   d. Fluid Saturation Post Injection: 60% CO_2 + 40% Brine
   e. CO_2 Density: 0.8 g/cc
   f. Bulk Modulus CO_2 : 0.5 GPa

The models show that there is no discernable change between the two fluid endmembers. Because there is no change, it is highly unlikely that 4D seismic or VSP measurements would be able to effectively monitor the migration of the CO_2 plume. Therefore, Milestone will not undertake any active seismic shoots during monitoring. This model will be updated with new data after the test well is drilled to continue to verify the negative hypothesis.

This lack of observable alteration to the seismic response by the change of fluids is likely due to the following factors: 1) low porosity for the fluid to occupy, thereby changing the total bulk modulus very little; 2) dolomite has one of the highest frame bulk moduli - in laymen's terms it is a rigid frame that has a very low strain response to stress; and, 3) low seismic frequency content due to very deep depths, seismic compressional waves and shear waves are attenuated with depth, therefore as depth increases frequency content decreases.

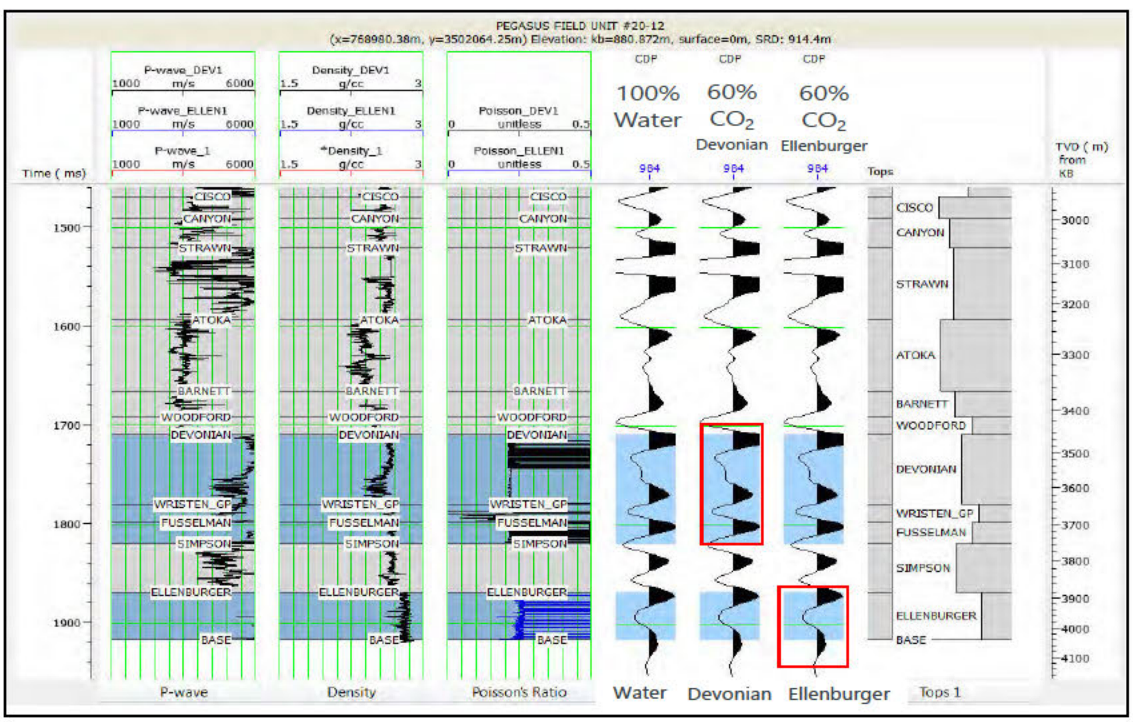


Figure 6-6: Fluid Substitution Forward Model of Pegasus Field Unit #20-12

6.9 Fiber Optic Monitoring

Milestone will deploy a downhole fiber optic cable behind the casing in the Injection Well and the In-Zone monitoring well. Each well will be equipped with a single cable containing five (5) fiber strings in three (3) tubes. There are three tubes inside the cable, each tube containing fibers for specific sensing technologies. Among these, there will be (1) dedicated buffered single mode DSS fiber, two (2) will be single-mode (SM) fibers, while the remaining two (2) will be multi-mode (MM) fibers. One SM fiber will serve for both Distributed Acoustic Sensing (DAS), while one MM fiber will be designated for Distributed Temperature Sensing (DTS). The other two fibers will act as backups in the event of damage. In the event the dedicated DSS SM fiber is damaged, the SM fiber(s) will serve as backup.

In the realm of distributed sensing technologies such as DAS, DSS and DTS, fiber optic serves as the fundamental medium for data collection and analysis. These systems employ fiber optic cables as distributed sensors, enabling the continuous monitoring of physical parameters such as acoustic signals, strain distribution, and temperature variations along the length of the fiber. In DAS, the fiber acts as a sensitive microphone, detecting acoustic disturbances through changes in backscattered light. DSS utilizes the fiber's intrinsic capability to measure strain by monitoring changes in its optical properties caused by mechanical deformation. Similarly, DTS relies on the fiber's sensitivity to temperature-induced changes in light signal transmission, allowing for precise temperature measurements along the entire length of the fiber.

6.9.1 Distributed Acoustic Sensing (DAS)

DAS data can be utilized for two applications. One is to monitor the microseismicity using the higher frequencies (> 10 Hz), called DAS Microseismic data and lower frequencies (< 0.1 Hz), also called low-frequency DAS (LF-DAS) data for strain monitoring.

6.9.1.1 DAS Microseismic

DAS microseismic data is very similar to geophone microseismic data with a difference being the number of components and number of sensors (array aperture). Downhole geophones have three components (perpendicular to each other) that are used to constrain the azimuth of the microseismic events, whereas fiber is equivalent to a single component (along the fiber cable) geophone. Because of its single component nature, there is an uncertainty in the azimuth of the events recorded by a single fiber cable. However, the uncertainty in the azimuth can be resolved in two scenarios.

- Having DAS data acquired from multiple fiber wells: Milestone will have DAS data continuously acquired in two injection wells and periodically acquired in two monitoring wells.
- Combine DAS data with downhole and/or surface geophones/seismometers: Milestone will have continuous fiber data from both injection wells and near surface seismometers/geophones.

Combining the microseismic data from fiber(s) with near surface seismometers and/or downhole geophones will increase both precision and accuracy of microseismic event locations.

6.9.1.2 DAS Strain (LF-DAS)

DAS strain data serves various applications contingent upon the fiber's installation location, be it within an injection or offset monitoring well. It entails a near-field direct assessment of stress alterations in the rock encircling the fiber. Strain data acquired within the injection well is termed In-well Strain (IWS), while that obtained in the offset well is denoted as Cross-well Strain (CWS).

CWS data serves to monitor the CO_2 pressure front, plume, and any strain proximal to the fiber stemming from fracture dilation, pore pressure changes, or fracture openings and closures. Moreover, the monitoring well fiber can detect any CO_2 leakage through its casing. Pre-injection CWS data establishes a baseline for strain and noise in the vicinity of the fiber. Deviations from this baseline signal treated as an anomaly in the data, prompting a thorough analysis to ascertain the underlying causes. This analysis will include integration with other datasets to corroborate whether these anomalies indicate the migration of the CO_2 pressure front or plume to the offset well, or if there is a CO_2 leak through the casing, or any other potential causes.

In the monitoring wells, baseline CWS data will be acquired for seven (7) days prior to the injection. Based on the CO_2 dynamic reservoir simulation models, it will take approximately three (3) years for CO_2 pressure front and seven (7) years for plume to migrate from CCS #2 to IZM #2 well. Post-injection, CWS data will be acquired yearly once (1) for the first two years and every six (6) months from third year onward as it takes about 3 years for the CO_2 pressure front to travel to the monitoring well from the injection well **(Section 2).**

IWS data will be continuously acquired in the injection wells, commencing with pre-injection baseline measurements. Unlike CWS data, IWS strain will exhibit abnormal signals whenever injection starts and stops due to pressure and temperature fluctuations in the wellbore. If abnormal strain signals originate from the top and propagate downward over time, it suggests that the signal's source is at the wellhead, likely caused by CO_2 entering the wellbore. Conversely, if the abnormal signal initiates from the bottom of the fiber and progresses upward with time, it indicates that the signal's source is at the bottom of the wellbore. This signal will undergo careful analysis by qualified experts to detect any potential CO_2 leaks through the casing or tubing.

In addition to direct DAS strain data, we will derive additional attributes, including Frequency Band Extracted (FBE) data across various frequency bands (1-10, 10-50, 50-200 Hz, etc.) and cumulative strain to aid in monitoring potential casing leaks, and a deeper comprehension of stress changes in proximity to the fiber.

6.9.2 Distributed Strain Sensing (DSS)

Distributed Strain Sensing (DSS) is another fiber technology that requires a special interrogator other than DAS interrogator. Both DAS and DSS measures strain on the fiber but using different scattering mechanisms. DAS works based on Rayleigh back scattering while DSS works on Brillouin back scattering. DSS measures absolute strain with high spatial resolution whereas DAS measures relative strain. DSS provides continuous measurements over long periods (timelapse measurements), making it suitable for static strain monitoring. DAS relies on the interaction between laser light and acoustic disturbances along the fiber. As a result, it is particularly effective in capturing dynamic strain events, such as microseismic events.

Another distinction between DAS strain and DSS lies in the fiber requirement. DSS necessitates a tight-buffered single mode (SM) fiber cable to accurately detect mechanical strain changes. Milestone will deploy a dedicated DSS fiber cable within a separate tube. If the DSS cable is damaged, the SM DAS cable can serve as a backup, but the data quality may be poorer. The DSS cable does not have a backup line due to the buffering.

6.9.3 Distributed Temperature Sensing (DTS)

Distributed Temperature Sensing (DTS) technology offers precise measurements of absolute temperatures within and around the wellbore, employing a high spatial resolution of 1 meter and a temperature resolution of 0.01-degC. DTS utilizes a multi-mode (MM) fiber, distinguishing it from DAS and DSS, which utilize single-mode (SM) fiber. In injection wells, the fiber spans from the well's top to the bottom of the seal, and throughout the entire wellbore in monitoring wells, providing a comprehensive temperature profile over time, and used to monitor CO_2 leaks and casing integrity.

Prior to commencing DTS recording, calibration occurs using known temperature measurements obtained either from the surface fiber or downhole temperature logs planned to run before injection commencement.

For monitoring CO_2 injection effects, pre-injection measurements establish the geothermal gradient within the wellbore, serving as baseline temperature. Any deviations from this baseline are deemed abnormal, potentially attributed to external factors such as CO_2 ingress from the wellhead or leakage along the casing from the reservoir.

Interpreting DTS data is straightforward. Temperature changes starting from the top of the fiber (typically the wellhead) and descending with time indicate CO_2 movement from wellhead. Conversely, changes originating from the fiber's bottom suggest CO_2 movement upwards, potentially through annuli or casing leaks. Abnormal temperature observations are cross-referenced with DAS strain and pressure gauge data installed in the annulus between casing and tubing.

LF-DAS Strain data from DAS or DSS are influenced by both temperature and rock stress changes surrounding the fiber. To accurately identify stress changes, temperature effects are removed from the strain data. Establishing a temperature-strain relationship facilitates this removal, given the direct proportionality between temperature and strain.

DTS data acquisition occurs at 5-minute intervals due to potential temperature stability over short durations. In injection wells, continuous DTS acquisition begins from the pre-injection baseline. In In-zone monitoring wells, data is acquired pre-injection and annually for the initial two (2) years, transitioning to biannual acquisitions thereafter.

6.9.4 Fiber Optic Data Retention

Fiber optic data recording frequency, recording interval, storage and deletion schedule of raw and processed data is presented in **Table 6-5**. It should be noted that raw fiber data will be kept for only one year due to the massive amount of data that is expected to be generated. Processed data will be retained for 10 years.

Data will be overwritten on a rolling basis. This retention strategy of raw and processed data is designed to align with the reporting schedule in **Section 6.1** to give the EPA UIC director and Milestone both time to respond to any anomalous fiber optic readings. It is expected that results from the processed data will answer nearly any historical questions.

It is expected that with the sampling frequency in **Table 6-5,** the interrogators will generate over 80 terabytes (TB) of raw data in the one-year retention timeframe.

Fiber optic cables generate significant data volumes due to their ability to perform high-resolution, continuous, and distributed sensing over long distances. They collect data at high frequencies and with fine spatial resolution, sometimes down to one meter (3.28 feet) or less. This results in numerous data points, as each segment of the cable acts as an individual sensor across potentially miles of infrastructure. Additionally, fiber optic systems can measure various parameters—such as temperature, strain, and pressure—simultaneously, contributing to the overall data load. When monitored continuously over extended periods, often years, the data generated becomes immense, requiring advanced storage, processing, and analysis to provide insights into subsurface conditions, optimize production, and maintain operational safety. Once the data is processed, any insights are likely to come from the processed data. It would take an extraordinary event or error in processing workflow to have to go back to the raw data and reprocess it. Milestone will keep the raw data for 1 year to account for the chance such an error or event occurs.

Table 6-5: Fiber Optic Data Parameters, Acquisition and Storage Timeline

Data Type	Min. Sampling Frequency	Min. Recording Frequency	Raw Data Storage Time	Processed Data Storage Time
DAS (Microseismic and Strain)	2 seconds	**Injection well:** Continuous. **In-Zone Monitoring well:** yearly once (1) for the first two years and every six months thereafter	1 year	10 years (strain data and located microseismic event waveform data only)
DSS	5 min	**Injection and In-Zone Monitoring wells:** yearly once (1) for the first two years and every six months thereafter contingent upon the usefulness of the data as fiber may not be suitable for DSS measurements	1 year	10 years
DTS	5 min	**Injection well:** Continuous. **In-Zone Monitoring well:** yearly once (1) for the first two years and every six months thereafter	1 year	10 years

6.10 Passive Seismicity Monitoring

6.10.1 Near Surface Seismometers

Throughout the operational phase of injection operations, continuous monitoring of seismicity will be performed. Existing seismometer stations within Texnet will be utilized. There is currently only one (1) Texnet station within 10 miles of the Injection Well (**Figure 6-9**). Five (5) additional Milestone owned broadband stations will be installed ("array" of near-surface seismometers) sufficient to confidently measure baseline seismicity 10 km (6.2 mi) radially from injection down to a magnitude of completeness of less than zero (<0) (**Figure 6-7**). The array will have a vertical uncertainty of <1,080 ft and a horizontal uncertainty of <1,500 ft (**Figure 6-8**). This magnitude of completeness and uncertainty analysis is based on forward modeling Milestone conducted through a consultant ISTI which is an expert in seismicity. Milestone owned stations will be deployed in a circular pattern around the AoR and one station will be deployed roughly in the center of the AoR.

The data collected in the near-surface seismometers will be continuously recorded at 200 Hz and monitored for potential seismicity magnitudes and hypocenter locations. The detectors will be co-located with water sampling locations and the detectors cemented below the surface to avoid surface noise and signal losses. Given the high sensitivity of this array, it is likely that real-time microseismic events will also be detected. See permit **Section 3** for NSSW well construction details.

Seismometers will record at a 5-millisecond frequency, or 200 Hz and data will be kept for the life of the project. Data will only be included in the report to UIC Director when a seismic event greater than magnitude one (1) is measured. Earthquakes less than magnitude 2.5, with hypocenters within 10 km of site, may not be analyzed by staff. Hypocenters within 10 km of site, over magnitude 2.5, will be reviewed by qualified seismologists. Baseline passive seismic data will be collected six (6) months prior to injection. If increasing trends of seismicity are observed, or a linear pattern is observed, a report on the trend will be submitted to the EPA UIC Director.

Seismicity risk is low in northern Upton County, see permit **Section 1** for further details on historical seismicity. There is a trend of earthquakes, mostly less than M2.0, located 5 miles west of the Well associated with Pegasus Field injection. This fault will not be affected due to low pressure change.

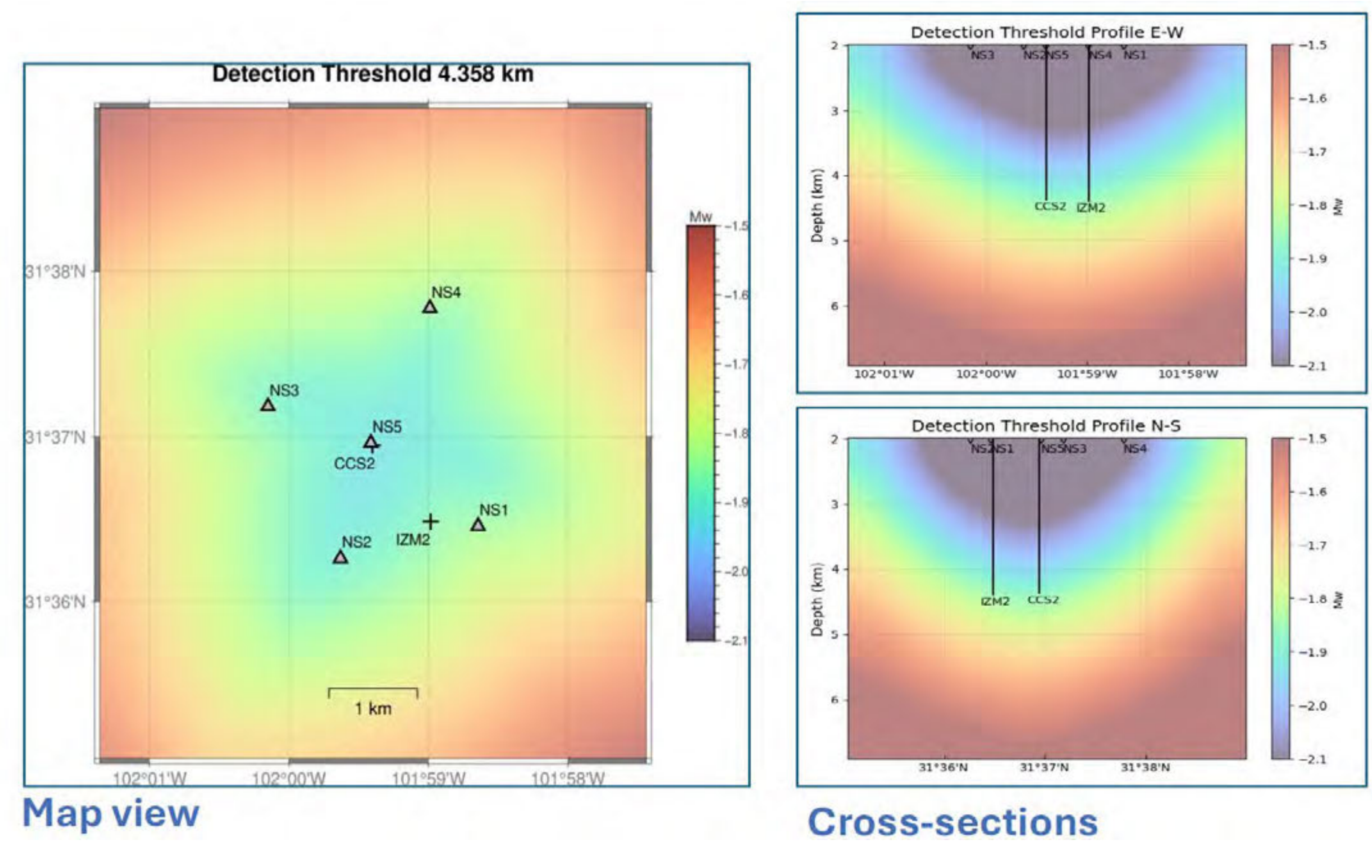


Figure 6-7: Forward Modeled Magnitude of Completeness
(Left) Map View of average magnitude of completeness at all depths, (Right) Cross Section views from N-S and E-W showing magnitude of completeness at depth, NS Wells = NSSW wells. Midland CCS2 in center

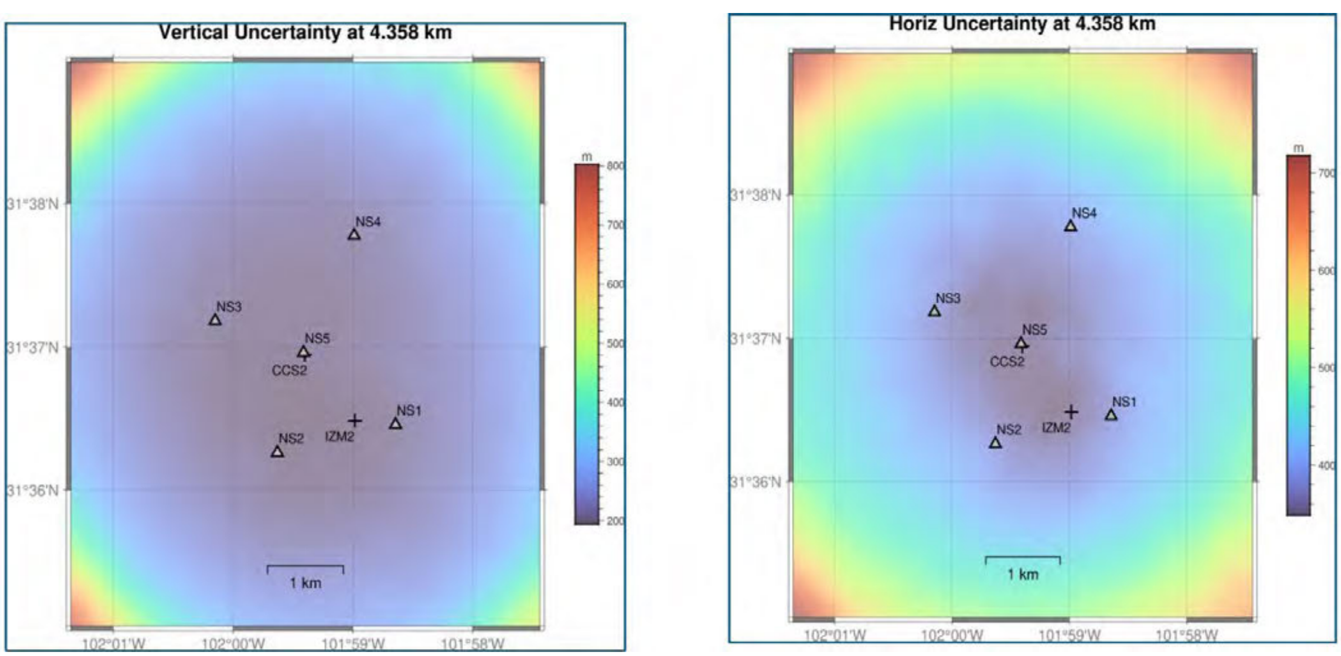


Figure 6-8: Forward Modeled Vertical and Horizontal Uncertainty for Earthquake Hypocenter
(Left) Vertical Uncertainty of Earthquake Hypocenters, (Right) Horizontal Uncertainty of Earthquake Hypocenters, NS Wells = NSSW wells. Midland CCS2 in center

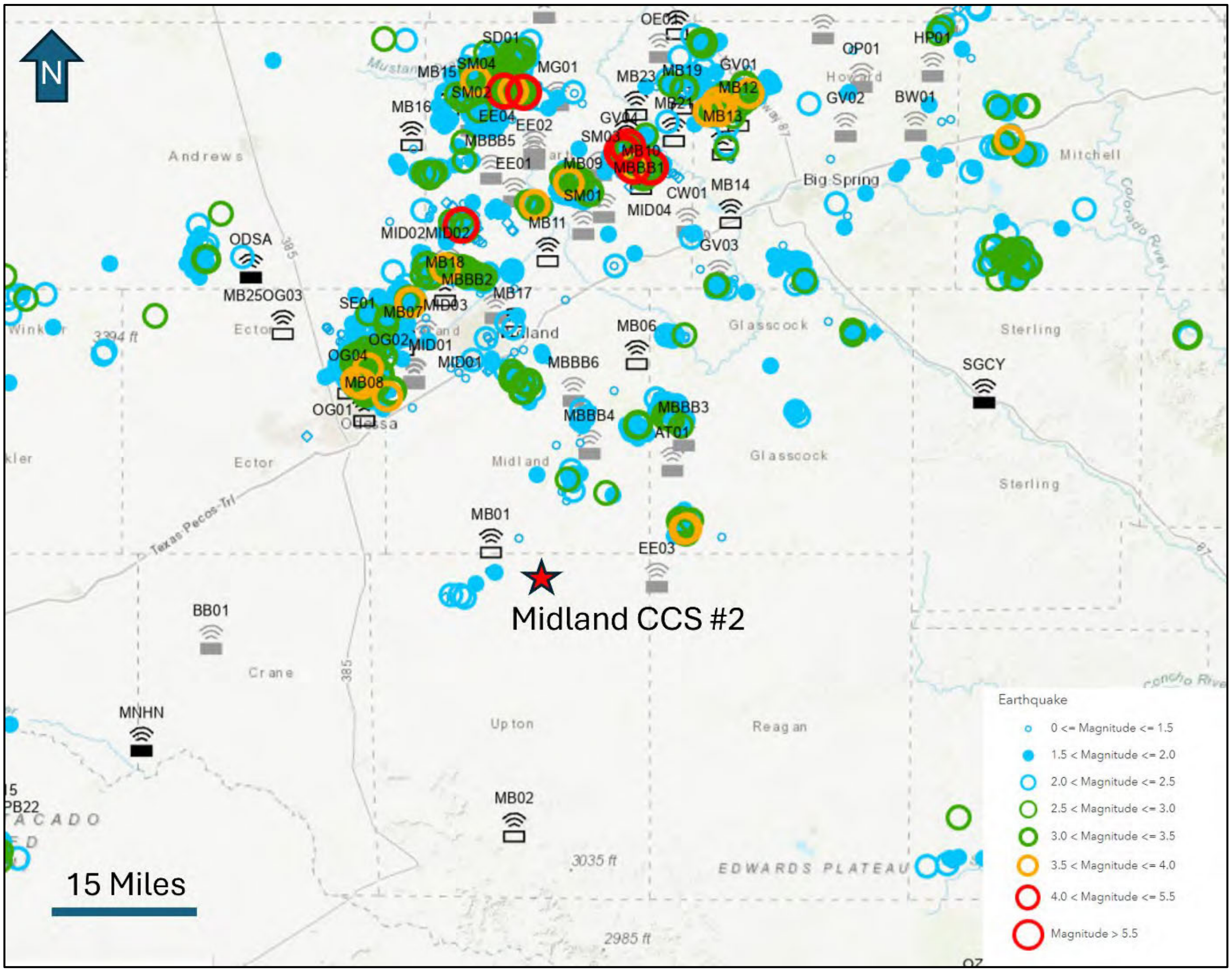


Figure 6-9: Map of Existing Texnet Detectors at time of application and Earthquakes Since 1/1/2017

6.10.2 Downhole Fiber (DAS Microseismic)

Fiber installed in the injection wells will continuously gather Distributed Acoustic Sensing (DAS) data to monitor induced seismicity. However, due to sensitivity limitations, the fiber can only detect events with a moment magnitude of +0.5 or higher. Any event detected by both the fiber and surface and near surface stations above magnitude 2.5 will undergo co-location to enhance depth accuracy. Conversely, if an event is detected solely by one of the downhole fibers, it will carry a 360-degree uncertainty in location azimuth, attributable to the single-component nature of the fiber. This azimuth uncertainty can be reduced if the event is recorded by multiple fiber wells.

6.10.3 Downhole Geophones (Microseismic)

Both near-surface seismometers and downhole fiber have limitations on detecting small magnitude events. Based on the previous experiences at Carbon Capture and Storage (CCS) sites, such as Shell Quest facility in Canada, it typically takes several years for induced seismicity, if any, to occur, usually within the basement (Briam et al., 2023). As depicted in **Figure 6-10**, seismicity distribution at the Shell Quest CCS facility indicates that most of the seismic events occurred after 2 years of injection initiation. Continuous monitoring of seismic activity using fiber optics and surface stations allows us to discern seismicity trends. In the event of heightened seismic activity, Milestone will deploy a retrievable geophone array in one or both monitoring wells. The depth of the geophone array will be determined based on observed seismicity from the fiber optics and surface stations. This measure aids in detecting any small-magnitude events (Mw ≥ -0.8) induced by injection and monitors the integrity of the Top Seal.

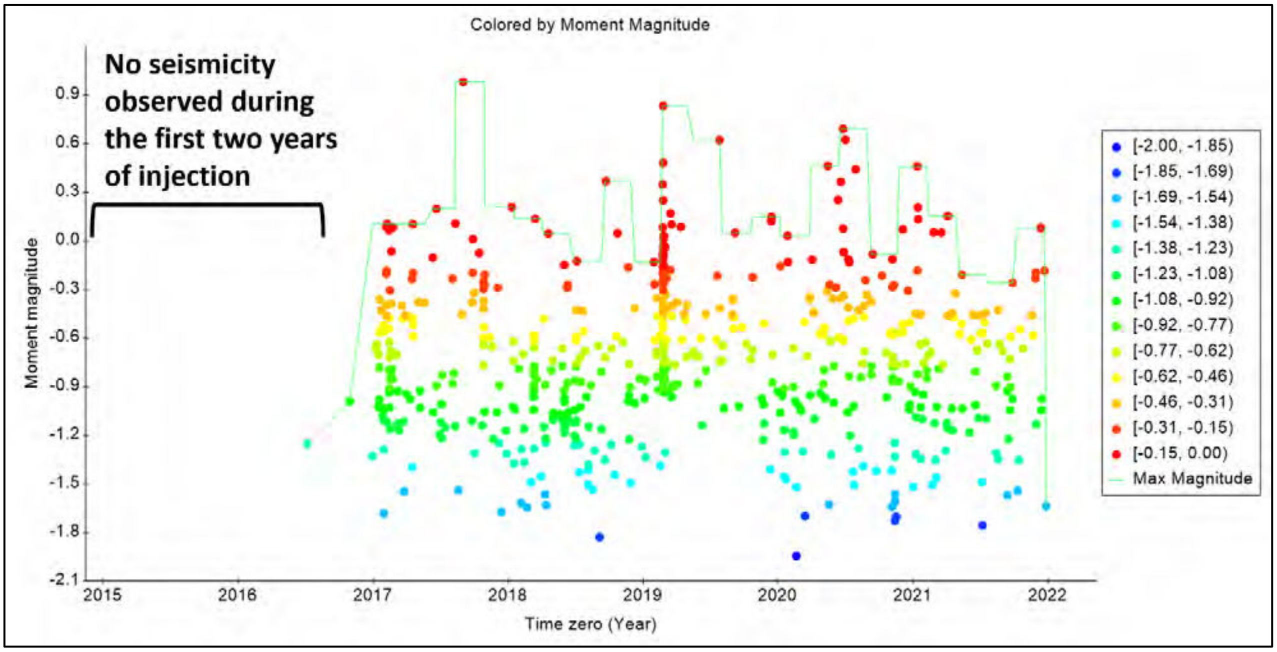


Figure 6-10: Seismicity distribution over time from Shell Quest facility (modified after Braim et al., 2023)

6.11 Soil Gas Monitoring / Other Testing and Monitoring [40 CFR 146.90 (h)]

Surface and near-surface environments will be monitored within the delineated AoR via groundwater wells (see **Section 6.5**) and vadose zone soil gas-sampling prior to CO_2 injection and during the injection phase of the project.

Milestone will test the soil for changes in CO_2 concentration. Six (6) soil gas profile stations will be installed: One at each of the Midland NSSW Wells (#1-#5) and one at the Midland IZM #1. The Midland NSSW #5 is within 100 ft laterally of the Injection Well. Baseline soil gas analyses will be provided to EPA prior to CO_2 injection operations. Once injection commences, soil gas will be measured at least once annually.

Milestone will amend the monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring using baseline data, and the amended monitoring plan will describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 40 CFR 144.12. An amended soil gas monitoring or surface air monitoring plan will be submitted to the EPA UIC Director within 90 days of receipt of baseline samples.

6.12 Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Milestone will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Milestone will analyze the CO_2 stream continuously using a continuous gas analysis device after the last stage of compression but before the wellhead. Milestone will employ a device that meets the temperature, pressure and rate requirements of the project. This could include any of the following but is not limited to the following: photometry-based methods, laser-based methods, gas chromatography, mass spectrometry or other suitable devices selected by the surface engineering team. The continuous gas analysis device will record data at least once every five (5) seconds and store data at least once every five (5) minutes.

6.12.1 Validation Sampling frequency

Milestone will sample the gas using a continuous gas analysis device. In addition, Milestone will sample the gas four (4) times annually, every three (3) months, using sample containers, in order to verify continuous field results.

6.12.2 Validation Sampling methods and Location

Milestone will sample the gas using a continuous gas analysis device. In addition, a sampling station will be installed downstream at the last stage of compression in the compressor building (or equivalent structure if a compressor is not needed). The sampling station will have the ability to purge and collect samples into a container that will be sealed and sent to the commercial third-party laboratory for analysis. All sample containers will be labeled with indestructible labels and ingrained markings. A unique sample identification number and sampling date will be recorded on the sample containers.

6.12.3 Validation Sample Analysis Methods

Samples will be analyzed by a third-party commercial laboratory using standardized analytical procedures outlined in **Table 6-6**. Milestone will use the International Society of Beverage Technologists (ISBT) best practices and guidelines for gas testing for each gas species and recommendations from a commercial laboratory on gas standards. Additionally, the isotopic analyses will be outsourced to a separate third-party specialized commercial laboratory that will employ standard analytical QA/QC protocols used in the industry.

Table 6-6: Summary of analytical and field parameters for groundwater samples

Parameter	Frequency	Analytical Methods
Carbon Dioxide (CO_2 Purity)	Twice Annually	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Oxygen		ISBT 4.0 (GC/DID) GC/TCD
Nitrogen		ISBT 4.0 (GC/DID) GC/TCD
Water Vapor		ISBT 3.0
Hydrogen Sulfide		ISBT 14.0 (GC/SCD)
Sulfur Dioxide		ISBT 14.0 (GC/SCD)
Carbon Monoxide		ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen		ISBT 7.0 Colorimetric
Total Hydrocarbons		ISBT 10.0 THA (FID)
Methane		ISBT 10.1 (GC/FID)
Acetaldehyde		ISBT 11.0 (GC/FID)
Ethanol		ISBT 11.0 (GC/FID)
Carbon Isotope		Isotope Ratio Mass Spectrometry

6.13 Data Validation of All Processes [16 Texas Statewide Rule §5.203 (a)(4)]

In accordance with Statewide Rule §5.203(a)(4), Milestone affirms that all descriptive reports included in this application have been prepared by qualified and knowledgeable professionals with relevant expertise in subsurface characterization and engineering standards. All future reports to be submitted to the director, as described in **Section 6.1.2**, will similarly be prepared by qualified and knowledgeable professionals with relevant expertise.

6.13.1 Professional Seals and Qualified Experts

Where appropriate and required, the reports have been signed and sealed by either a professional geologist (P.G) or professional engineer (P.E.). It is Milestone's understanding that in the state of Texas, there is unfortunately no legal definition of a professional log analyst. Therefore, where documents are required to be prepared by a professional log analyst, a professional geologist (P.G.) instead has prepared the documents and reports. It should be noted that the P.G. who supervised the work contained in this permit is a longstanding member of the Society of Petrophysicists and Well Log Analysts (SPWLA) and has previously served on the board of directors of the aforementioned society.

This work has been conducted as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, a licensed professional engineer or geoscientist has conducted the geologic and hydrologic evaluations required in this permit and has affixed the appropriate seal on the resulting reports of such evaluations.

6.13.2 QASP Additional description

As required, a comprehensive Quality Assurance and Surveillance Plan (QASP) has been included in **Section 13- Appendix C**, outlining procedures for validating analytical laboratory data and calibrating field instruments. The QASP also provides a detailed explanation of the sampling methodologies and data acquisition techniques employed to ensure accuracy, reliability, and consistency throughout the project. Documentation of data validation and verification protocols is enclosed to demonstrate the integrity and rigor of the testing and monitoring program.

6.13.3 Data Validation and Verification

To the extent this information is not provided elsewhere in the application, it is hereby submitted in response to the requirements of Statewide Rule §5.203(a)(4). Milestone has established procedures for laboratory data validation and verification, including the use of standard reference materials, duplicate sample analysis, and method blanks to ensure accuracy and precision. Field instruments such as pressure gauges, flow meters, and multi-parameter water quality sondes are subject to routine calibration against NIST-traceable standards. Sampling and data acquisition protocols follow EPA SW-846 and ASTM guidelines, with chain-of-custody documentation maintained throughout all sample handling. All logging tools will be calibrated at the base and in the field prior to measurement. Logs will have a repeat pass to ensure data verification. Fiber-optic cables will be regularly tested for changes in signal to noise ratios, return loss and attenuation as well as drift over time.

These measures collectively ensure the reliability, traceability, and scientific defensibility of all collected data, consistent with the requirements of Rule §5.203(a)(4).

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment G: Injection Well Plugging Plan

[40 CFR §146.92]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Reviewed by

Octane Energy

310 W Wall St., Suite 300

Midland, Texas 79701

Updated 16 April 2025

Table of Contents

List of Tables

List of Figures

8.0 INJECTION WELL PLUGGING PLAN [40 CFR 146.82(a)(16),146.92(b) 146.92]

Injection well plugging and abandonment will be conducted according to the procedures herein. Upon completion of the Project, or at the end of the life of the Well, the Well will be plugged and abandoned to meet the requirements of 40 CFR 146.92 and all state and local regulations. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect USDWs. Prior to plugging the injection well, any necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plan will be submitted to the UIC Program Director no later than 60 days prior to plugging of the Well.

Following receipt of the approved plugging plan, the Well will be flushed with a kill weight buffer fluid. A minimum of three (3) tubing volumes will be injected without exceeding fracture pressure.

Bottomhole pressure measurements will be recorded, and the well will be logged, and pressure tested to ensure mechanical integrity prior to plugging. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The plugging procedure is presented herein.

All casing in this well will be cemented to surface at the time of construction and will not be retrievable at abandonment. The injection tubing, valves inside tubing and packer will be removed. After the tubing and packer are removed, a combination of bridge plugs and cement plugs will be set to plug the well.

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.

8.1 Planned Tests / Measures to Determine Bottomhole Reservoir Pressure [146.92 (b)(1)]

Milestone will record bottomhole pressure from a downhole pressure gauge and calculate kill fluid density.

8.2 Planned External Mechanical Integrity Test(s) [146.92 (b) (2)]

Milestone will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity prior to plugging the injection well as required in 40 CFR 146.92(a).

Table 8-1: Pre-Plugging External Tests

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

8.3 Plugging Procedures

Notification, regulatory and plugging procedures will include:

8.3.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c) and 16 TAC §5.203(k), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) Bottomhole reservoir pressure will be measured using downhole pressure gauges permanently installed behind the production casing.
3) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
4) Mechanical Integrity of the tubing-casing annulus will be demonstrated by pressure testing, as described in **Section 6**.
5) The wellbore will be flushed with a kill weight buffer fluid, 9 ppg minimum, prior to pulling the tubing and packer. Minimum of three (3) tubing volumes.
6) The tubing and packer will be removed. A packer milling and retrieval bottomhole assembly will be run to mill the packer slips and pull the packer assembly.
7) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.
8) In compliance with 16 TAC §5.203(k), file a notice of intention to plug and abandon (Form W-3A) a well with the RRC at least five (5) days prior to the beginning of plugging operations.

8.3.2 Plugging Activities

1) Run and position workstring at 12,200 feet and pump a 1,649-foot balanced corrosion resistant cement plug from TD to the Devonian top from 13,849 feet to 12,200 feet.
2) Wait on cement, tag and pressure test the corrosion resistant cement plug.
   a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 12,200 feet.
3) Pull out of hole and make up a corrosion resistant bridge plug.
4) Run CRA bridge plug and set with workstring in the Woodford shale at 12,160 feet.
   a. Tag and pressure test bridge plug.
5) Position workstring to bridge plug at 12,160 feet and pump a 300-foot corrosion resistant cement plug across the Woodford from 12,160 feet to 11,860 feet.
6) Wait on cement, tag and pressure test the corrosion resistant cement plug.
   a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,860 feet.
7) Position workstring at 11,603 feet and pump a 200-foot balanced corrosion resistant cement plug across the Atoka top from 11,603 feet to 11,403 feet.
8) Wait on cement, tag and pressure test the cement plug.
   a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,403 feet.
9) Position workstring at 10,945 feet and pump a 200-foot balanced cement plug across the Strawn top from 10,945 feet to 10,745 feet.
10) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional cement plug will be set up to 10,745 feet.
11) Position workstring at 9,224' and pump a 324-foot balanced corrosion resistant cement plug

across the Wolfcamp top and across the intermediate casing shoe from 9,224 feet to 8,900 feet.

12) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 8,900 feet.
13) Position workstring at 7,671 feet and pump a 200-foot corrosion resistant cement plug across the Sprayberry from 7,671 feet to 7,471 feet.
14) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 7,471 feet.
15) Position workstring at 4,220 feet and pump a 200-foot balanced corrosion resistant cement plug across the San Andres top from 4,220 feet to 4,020 feet.
16) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 4,020 feet.
17) Pull out of hole and make up a cast iron bridge plug.
18) Run cast iron bridge plug and set with workstring at 1,350 feet.
    a. Tag and pressure test bridge plug.
19) Pump a 50-foot corrosion resistant cement plug across the surface casing shoe and USDW from 1,300 feet to 1,250 feet.
20) Wait on cement, tag and pressure test the cement plug.
    a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 1,250 feet.
21) Position workstring at 400 feet and pump a 100-foot cement plug 400 feet to 300 feet.
22) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional cement plug will be set up to 300 feet.
23) Pump a 100-foot balanced corrosion resistant cement plug from 100 feet to surface.
24) Cut and cap casing 3 feet to 4 feet below ground level.

A certified plugging report will be submitted to the UIC Program Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure.

8.4 Plug Information

The CRA bridge plug, 22CR/25CR or equivalent, and all corrosion resistant cement will be compatible with the injection stream and downhole conditions. The corrosion resistant cement blend, and required certification documents, will be submitted with the final plugging procedure. The operator will report cement densities and retain samples of the cement used for each plug. For all cement plugs, 0% excess will be used to ensure isolation is achieved. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

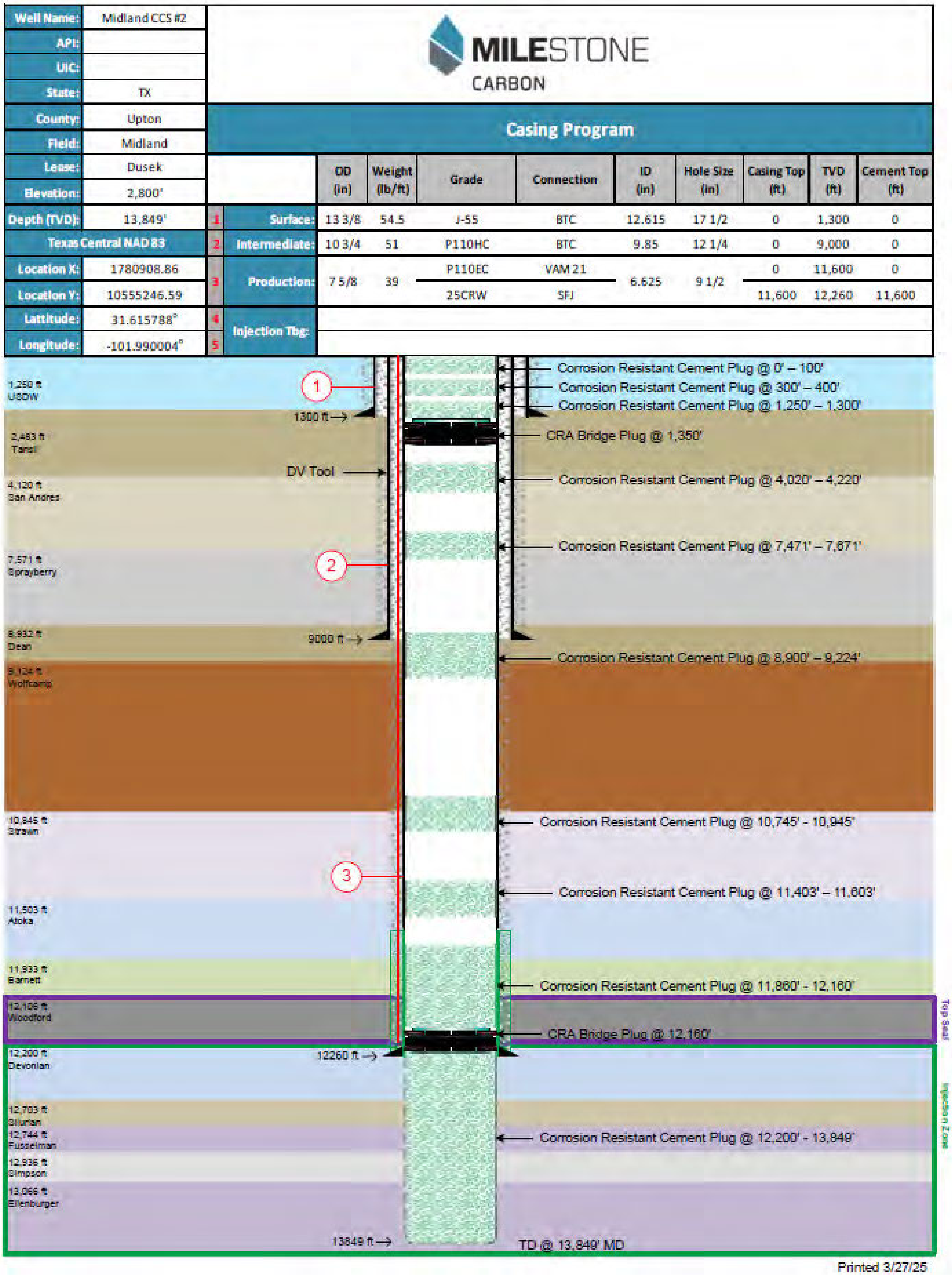
Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 8-2 and **Figure 8-1** present details for each plug and the proposed plugging schematic, respectively.

Table 8-2: Midland CCS #2 Well Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10	Plug #11	Plug #12
Diameter of boring in which plug will be Placed (inches)	6.125	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625	6.625
Sacks of cement to be used (sks)	322	NA	68	45	45	73	45	45	NA	12	23	23
Slurry volume to be Pumped (cu.ft.)	337	NA	71.8	47.9	47.9	77.6	47.9	47.9	NA	12	23.9	23.9
Slurry Weight (lb/gal)	16.4	NA	16.4	16.4	16.4	16.4	16.4	16.4	NA	16.4	16.4	16.4
Length of cement	1,649	NA	300	200	200	324	200	200	NA	50	100	100
Calculated top of Plug (ft)	12,200	12,160	11,860	11,403	10,745	8,900	7,471	4,020	1,350	1,250	300	0
Bottom of plug (ft)	13,849	NA	12,160	11,603	10,945	9,224	7,671	4,220	NA	1,300	400	100
Type of cement or other material	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Circulation	Workstring	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation	Workstring	Circulation	Circulation	Circulation



Well Name:	Midland CCS #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,800'
Depth (TVD):	13,849'
Texas Central NAD 83	
Location X:	1780908.86
Location Y:	10555246.59
Lattitude:	31.615788°
Longitude:	-101.990004°

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	10 3/4	51	P110HC	BTC	9.85	12 1/4	0	9,000	0
3	Production:	7 5/8	39	P110EC	VAM 21	6.625	9 1/2	0	11,600	0
				25CRW	SFJ			11,600	12,260	11,600
4	Injection Tbg:									
5										

Figure 8-1: Midland CCS #2 Well Plugging Schematic

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment H: Emergency and Remedial Response Plan (ERRP)

[40 CFR §146.94(a) - (d)(3)]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

MILESTONE CARBON

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC
840 Gessner Rd, Suite 600
Houston, Texas 77024

Updated 14 January 2026

Table of Contents

List of Tables

List of Figures

10.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (ERRP) [40 CFR 146.82(a)(19), 146.94(a)]

This Emergency and Remedial Response Plan (ERRP) for the Well is provided to meet the requirements of 40 CFR 146.94(a). The comprehensive plan describes potential adverse events that could occur in the development, operation and post-closure phases of the project and the actions to be taken in the unlikely event of such an emergency at the South Midland Facility or within the identified AoR. The ERRP describes the potential affected resources, lists entities and individuals to be notified, and provides actions to be taken expeditiously to mitigate any emergency and protect human health and safety of the environment, including USDWs.

This plan describes actions that Milestone will take in the event of an emergency that could endanger any USDW within the AoR during construction, operation, or post-injection site care. Such events may include unplanned CO_2 release or detection of unexpected subsurface movement of CO_2 or fluids in or from the injection zone.

If Milestone obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, Milestone will perform the following actions:

1) Initiate shutdown plan for the injection well.
2) Take all steps reasonably necessary to identify and characterize any release.
3) Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4) Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the following protocol will be employed:

> Milestone will immediately cease injection. However, given the high injection pressures, supercritical fluid within the wellbore, and high injection rates, Milestone will, in consultation with the UIC Program Director, determine appropriate pre-planned shut-down procedures that allow for safe shutdown of the well and associated mid-stream infrastructure that does not endanger human health, equipment, or the environment.

10.1 Local Resources and Infrastructure in AoR

10.1.1 Description of Project Area

The Facility is located in the near the city of Midkiff, which is an unincorporated desert village in northeastern Upton County, Texas, United States. It lies along Farm-to-Market (FM) 2401 and FM 3095 north of the city of Rankin, the county seat of Upton County, and is primarily an agricultural and petroleum-related community with a total population of 780 and 21 businesses.

The closest highly populated area is Midland, Texas which is about 45 miles northwest of the Facility (**Figure 10-1**). However, there are a large number of oilfield related structures in the vicinity.

There are over 53 identified structures within the AOR. These buildings are utilized for either residential, oil and gas, industrial, or agricultural use. There are four (4) inhabited commercial structures, two (2) temporary oil and gas office buildings, the Burritos Rey Restaurant and the Milestone Energy Waste Facility. There are two (2) residential houses within the AoR. One (1) is a temporary trailer house on the southern end of the AoR and one (1) is a permanent structure on the northeast side of the AoR. The permanent house north of the Milestone Midland Facility has associated barns and storage buildings. There are one-hundred-sixty-eight (168) total structures within a 2-mi radius of the injection well. (**Figure 10-2**)

Additionally, there are 71 oil and gas wells within the AoR and 68 water wells within the AoR, listed in Section 1.14. Many of these wells have associated surface facilities, although sometimes there are multiple wells on a single surface facility. Industrial equipment associated with oil and gas such as compressors, pipeline facilities, pumpjacks, antennas are located in the area.

Water and mineral resources in the vicinity of the Facility that may be affected by a potential emergency event from the Well are described in maps located in **Section 1.3**.

There are no drinking water treatment plants or other water-related infrastructure in the vicinity of the Facility that may be affected as a result of an emergency associated with the Well.

In addition to the proposed facility, Milestone operates two (2) affiliate oilfield waste facilities within 3 miles of the proposed facility.

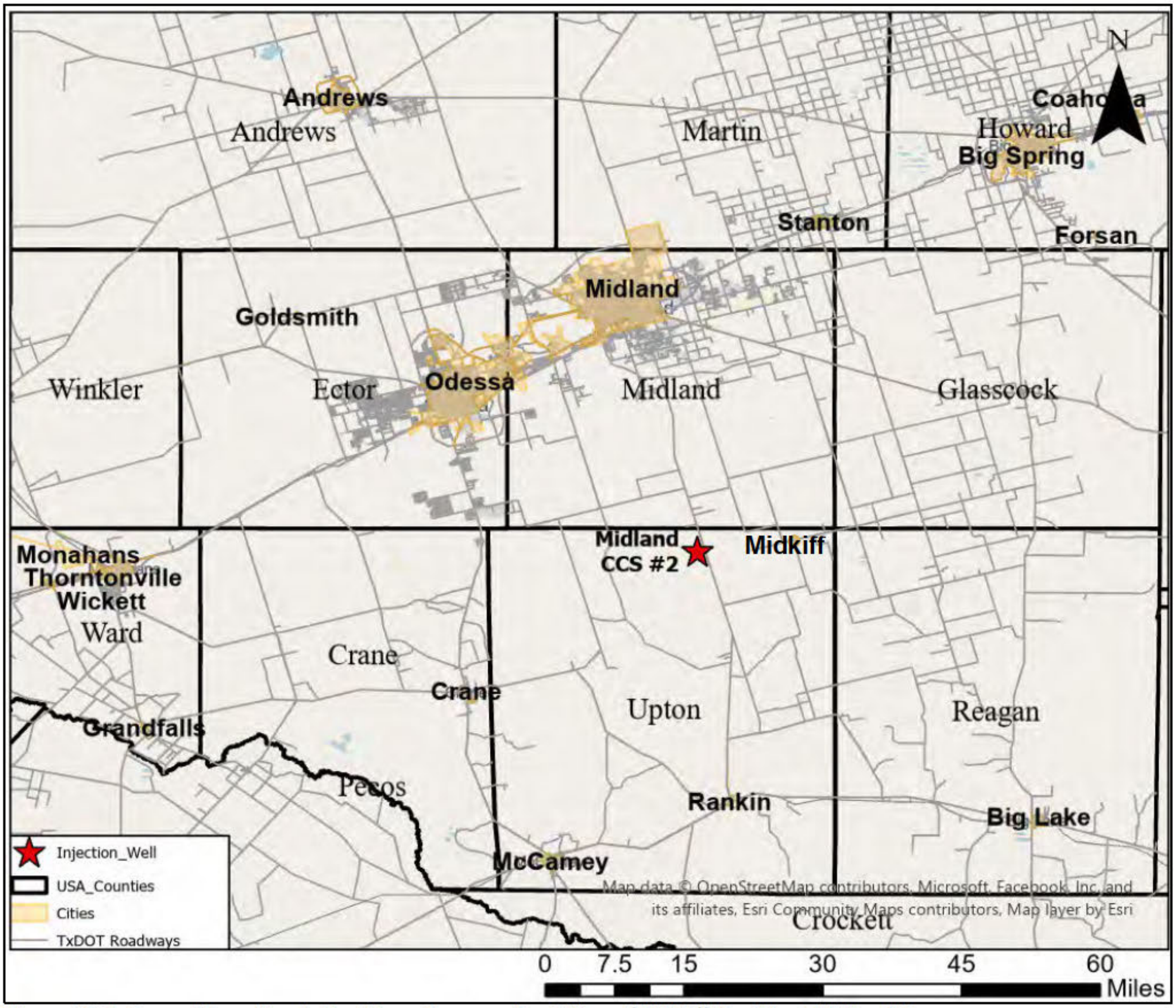


Figure 10-1: General Location Index Map – Surrounding Cities of Midkiff, Rankin & Midland, Texas
The Midland CCS #2 Well will be situated in the northern part of Upton County, Texas. The Well will be drilled at latitude 31.615788°N, longitude -101.990004°W (NAD83).

Resources and infrastructure addressed in this plan are shown in **Figure 10-2**

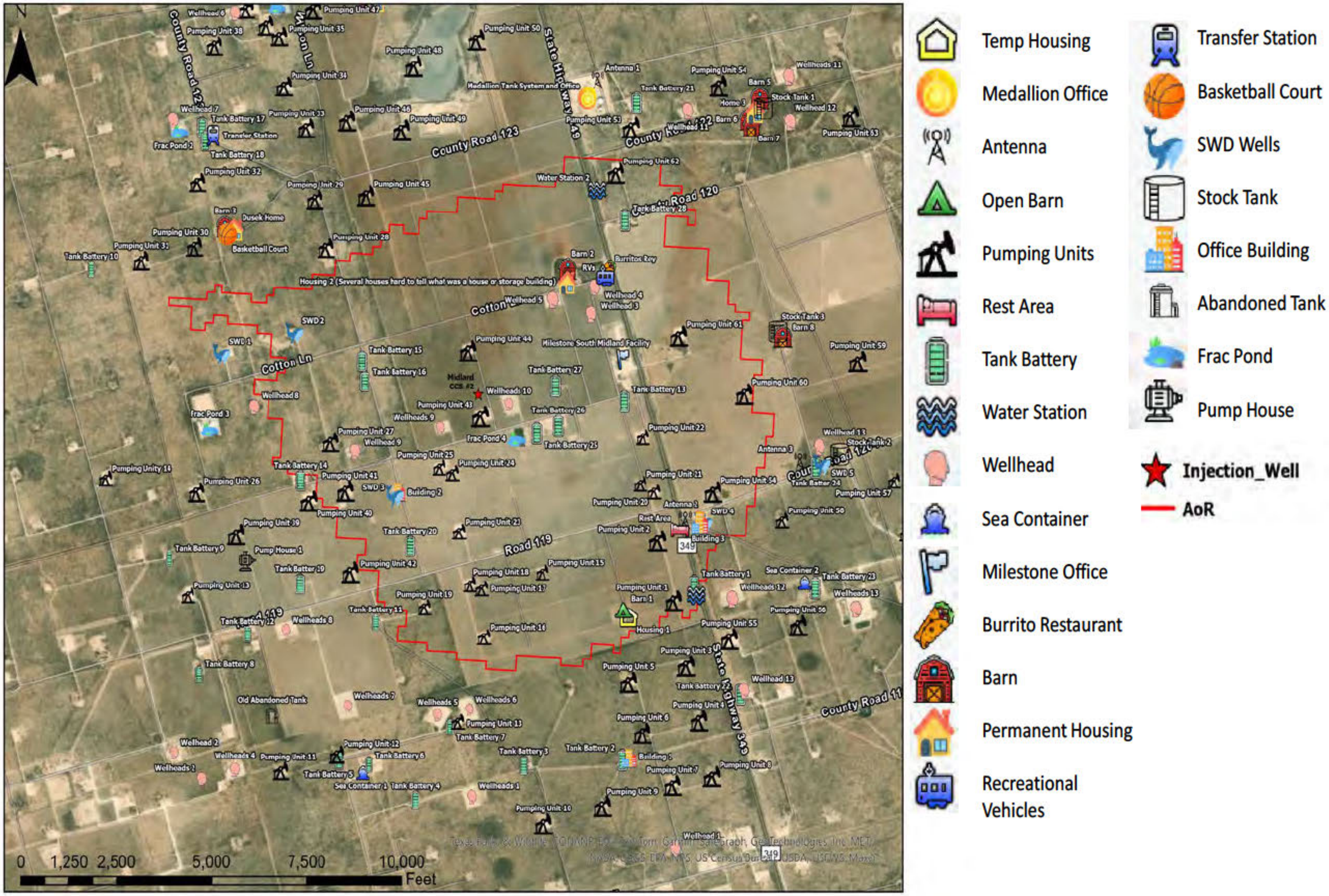


Figure 10-2: Map of Surface Site Resources and Infrastructure within the AoR

10.2 Potential Risk Scenarios

Several scenarios could activate an emergency response. This ERRP considers any adverse incident with the potential of causing personal injuries, USDW contamination, or property damage as an "event."

The scope of response, response actions, and order of activities will be proportionate to the severity and impacts of the event and implemented as outlined in this ERRP. "Emergency events" are categorized as shown in **Table 10-1**.

The protocols may be modified and refined based on the specific circumstances and conditions of the event as well as any discussion with governmental authorities having jurisdiction.

Table 10-1: Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major Emergency	Poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. ***Example***: well blowout while injecting
Serious Emergency	Poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken. ***Example:*** malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment
Minor Emergency	Poses no immediate risk to human health, resources, or infrastructure. ***Example***: higher pressure reading observed in monitoring wells with no potential to move fluid.

Discovery of an event triggers the corresponding response plan proposed herein. Response plan actions and activities will depend upon the circumstances and severity of the event. Milestone will address an event immediately and, when required, will communicate the event to the UIC Program Director within 24 hours of discovery. Tables of emergencies and responses are found in **Tables 10-2 to 10-7.**

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

If an event triggers cessation of injection and remedial actions, Milestone will demonstrate the efficacy of the response actions to the satisfaction of the UIC Program Director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC Program Director. See permit **Section 10.8**.

10.2.1 Event Description: Well Integrity Failure

Integrity loss of the injection well and/or a monitoring well may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
  - ✓ Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
  - ✓ Annulus pressure indicates a loss of external or internal well containment.
  - ✓ Pursuant to 40 CFR 146.91(c)(3), Milestone must notify UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

If CO_2 escapes to the surface:

- If there is a report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated.
- A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak.
- Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas.
- Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved, not vented, due to the dangerous composition of the gas.

Table 10-2: Event Description & Response Scenario 1 | Well Integrity Failure

Emergency ID	Response
Risk Level:	**Medium**
Timing / Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Any Phase
Prevention and Detection:	• Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase • Pressure, rate, and mechanical integrity monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan.
Potential Response Actions:	• 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 a Major or Serious emergency: ✓ Initiate shutdown plan. Steps could include: ▪ Close wellhead valve. ▪ Monitor well and annulus pressures. ▪ Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone. ▪ Pull and replace the tubing or the packer. ▪ Install chemical sealant barrier and or attempt cement squeeze to block leaks. ▪ Demonstrate Mechanical Integrity per the methods discussed in Testing and Monitoring Plan. ✓ If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director) • For Minor emergency:

Emergency ID	Response
	✓ 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
Response Personnel:	Drilling / workover crews or operations personnel
Equipment:	BOP. Cement. Pressure, rate, and mechanical integrity monitoring instrumentation

10.2.2 Event Description: Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Table 10-3: Event Description & Response Scenario 2 | Injection Well Monitoring Equipment Failure

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During injection and Post-injection
Prevention and Detection:	• Well maintenance and monitoring will be conducted continuously to avoid this scenario • Pressure and mechanical integrity monitoring instrumentation will be deployed for well maintenance and monitoring • Maintenance will be performed in accordance with manufacturer's recommended schedule • Periodic calibration checks will be performed on equipment in accordance with manufacturer's recommended schedule
Potential Response Actions:	• 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 a Minor emergency: ✓ Conduct assessment to determine whether there has been a loss of mechanical integrity and determine event severity ✓ If there has been a loss of mechanical integrity, initiate shutdown plan ✓ Implement and repair/replacement plan if needed ✓ Calibrate repaired or new equipment ✓ Evaluate resumed injection at reduced pressure
Response Personnel:	Facility operations personnel
Equipment:	• Pressure and mechanical integrity monitoring instrumentation • Calibration equipment • Repair equipment

10.2.3 Event Description: Spill

This event could occur during the drilling of the wellbore due to an accidental release of drilling fluids, hydrocarbons, chemicals, brine etc. during drilling and completion or workover operations.

Table 10-4: Event Description & Response Scenario 3 | Spill

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Drilling or Workover of Injection or Monitoring Wells
Prevention and Detection:	• Maintain appropriate mud weights as expected for the area based on offset well data Monitor rate of drilling fluid returns versus rates pumped, penetration rates, pump pressures, etc. • Properly maintained blowout preventers to prevent accidental release of drilling fluids or hydrocarbons • Spill prevention equipment on drilling or workover rig
Potential Response Actions:	• 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 Minor emergency: ✓ Stop drilling; close the blowout preventer; insert rams into the well; read and record stabilized shut-in pressures. ✓ Kill the well by pumping fluid down the wellbore that is heavier than the current fluid until the well stops flowing. ✓ Contain spill using available equipment such as absorbents, booms, etc. ✓ Notify appropriate regulatory authority and supervisory personnel ✓ Immediately take samples around the point of entry ✓ Initiate Spill Prevention, Control and Countermeasures Plan for facility
Response Personnel:	Onsite drilling personnel and supervisors
Equipment:	Drilling rig, mud logging equipment, blowout preventers with annular rams, drilling fluid materials to increase mud weight adequately. Spill kit

10.2.4 Event Description: CO_2 or Subsurface Fluid Migration

This event could occur if the plume or other subsurface fluids reach faults or fractures that allow migration into another zone, including the USDW, or to the surface. Failure of the confining zone could also cause CO_2 or subsurface fluids to migrate.

Table 10-5: Event Description & Response Scenario 4 | CO_2 or Subsurface Fluid Migration

Emergency ID	Response
Risk Level:	**Medium**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During injection and Post-injection
Prevention and Detection:	The CO_2 plume will be monitored as described in the Testing and Monitoring Section (**Section 6**)
Potential Response Actions:	• 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 ✓ Use Ambient Reservoir Monitoring system and/or Vertical Seismic Profile system to assess location and degree of CO_2 movement, as described in the Testing and Monitoring Plan ✓ If the presence of indicator parameters are confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to: ▪ Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of the impact; and ▪ Remediate unacceptable impacts to the affected USDW ✓ If groundwater/USDW is impacted: ✓ Pump carbon dioxide-contaminated groundwater to the surface and aerate it to remove carbon dioxide. ✓ Apply "pump and treat" methods to remove trace elements. ✓ Drill relief wells that intersect the accumulations in groundwater and extract carbon dioxide. ✓ Provide alternative water supply if ground water-based public water supplies are contaminated. ✓ If surface water is impacted: ✓ Shallow lakes will quickly release dissolved carbon dioxide back into the atmosphere. ✓ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ✓ Continue monitoring of plumes at a more frequent interval (frequency to be determined by Milestone and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed ✓ If the plume continues to migrate out of the zone or beyond the expected plume extent, recomplete up hole into the next planned injection interval.
Response Personnel:	Operations personnel
Equipment:	Depends on the cause of leak, hydraulic barrier, pump, water testing kit

10.2.5 Event Description: Natural Disaster

A natural disaster could impact the normal operation of the injection well. For example, weather-related disasters (e.g., tornado or lightning strike) may impact surface facilities.

Table 10-6: Event Description & Response Scenario 5 | Natural Disaster

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	Any phase.
Prevention and Detection:	• Proper wellbore design, including proper cement and metallurgy of the casing and tubing will be implemented in the construction phase • Pressure and rate monitoring, pressure fall-off tests, annulus pressure tests, etc., will all be performed per the Testing and Monitoring Plan • Weather event monitoring and communication will be implemented
Potential Response Actions:	• 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 a Major or Serious emergency: ✓ Initiate shutdown plan. Steps could include: ▪ Close wellhead valve. ▪ Monitor well and annulus pressures. ▪ Determine the cause and severity of failure to determine if any release of the CO_2 stream or formation fluids may have been released into any unauthorized zone. ▪ Pull and replace the tubing or the packer. ▪ Install chemical sealant barrier and or attempt cement squeeze to block leaks. ▪ Demonstrate Mechanical Integrity per the methods discussed in Testing and Monitoring Plan. ✓ Notify emergency contacts ✓ If contamination is detected, identify and implement appropriate remedial actions (in consultation with the UIC Program Director) • For Minor emergency: ✓ 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 notify emergency contacts
Response Personnel:	Operations personnel, local Fire and or Sheriff's Department or Other Emergency Contacts
Equipment:	Depends on the type of Natural Disaster

10.2.6 Event Description: Induced Seismic Event

Induced seismic events typically refer to minor seismic events that are caused by human activity which alter the stresses and fluid pressures in the earth's crust. Induced seismicity could potentially result from the injection of fluids into subsurface formations that change the stress state of pre-existing faults, which causes fault plane movement and energy release.

Most induced seismic events are extremely small (microseismic), but in some instances are great enough to be felt by humans. Case histories of induced seismic events associated with fluid disposal wells show seismic events as far away as about 10 to 12km (6.2 to 7.4 miles). Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside a 10km (6.2) radius from the wellhead. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 10km (6.2 mile) radius of the injection well.

To monitor the area for seismicity, the site will install five (5) near surface seismic monitoring stations and borehole monitoring stations that continuously record (at 5 millisecond frequency) the site's seismic activity (see permit **Section 6**). In addition to these stations, Milestone will monitor for seismicity using distributed acoustic sensing fiber optic cable (DAS) cemented within wellbore annuli. Finally, the USGS and TexNet have deployed a network of surface seismic monitoring stations and borehole monitoring stations in this area (Map of TexNet stations can found in permit **Section 6**)

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events (**Figure 10-3**), the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions. In **Table 10-7**, the Milestone Seismic Monitoring System is presented. The table corresponds each level of operating status with the threshold conditions and operational response actions.

Table 10-7: Event Description & Response Scenario 6 | Induced Seismic Event

Emergency ID	Response
Risk Level:	**Low**
Timing/Phase of Event: *(Construction, pre-injection, during injection, and/or post-injection).*	During Construction, During injection, Post Injection
Prevention and Detection:	Near Surface Seismometer Water well: Cemented Geophones Injection well: DAS microseismic monitoring Monitoring well: DAS microseismic monitoring
Potential Response Actions:	Follow the seismicity response plan **Tables 10-8**
Response Personnel:	Operations personnel, third party seismologists, Milestone geology team, Milestone regulatory team.
Equipment:	Near surface seismometer network. Injection well fiber-optic cable based seismic monitoring.

Table 10-8: South Midland Facility Seismic Monitoring System

South Midland Facility Seismic Monitoring System: Green thru Red for seismic events > M1.0 with an epicenter within an 6.2-mile radius of the injection Well

Operating State	Threshold Condition	Response Action
GREEN	Seismic events less than or equal to M2.0[1]	1. Continue site activities per permit conditions
YELLOW	Five (5) or more seismic events within a 30-day period having a magnitude greater than M2.0[1] but less than or equal to M2.5[1]	1. Continue site activities per permit conditions. 2. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility.
ORANGE	Seismic event M2.5-3.0[1] with local observation or felt report[2] OR Seismic event M3.0-3.5[1] but no felt report[2]	1. Continue site activities per permit conditions. 2. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 3. Review seismic operational data. 4. Report findings to the UIC Program Director and issue corrective actions[3]
MAGENTA	Seismic events M3.0-3.5[1] with local observation report or felt report[2] OR Seismic events greater than M3.5[1] but no local observation or felt report[2]	1. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 2. If M3.5+, Shut-in injection well while an investigation can be performed 3. Limit facility access to authorized personnel only. 4. Communicate with Milestone personnel and local authorities to initiate evacuation plans, as necessary. 5. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 6. Determine if leaks to groundwater or surface water occurred. 7. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 8. Review the seismic and operational data. 9. Report findings to the UIC Program Director and issue corrective actions[3]
RED	Seismic events greater than M3.5[1] , with local observation or felt report[2] and local report and confirmation of damage[4].	1. Within 24 hours of the incident, notify the UIC Program Director and TXRRC of the operating status of the facility. 2. Shut in injection well while an investigation can be peformed 3. Limit facility access to authorized personnel only. 4. Communicate with Milestone personnel and local authorities to initiate evacuation plans, as necessary. 5. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 6. Determine if leaks to groundwater or surface water occurred. 7. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 8. Review the seismic and operational data. 9. Report findings to the UIC Program Director and issue corrective actions[3]

1. Determined by the local Milestone or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
2. Confirmed by the local report of felt ground motion or reported on the USGS "*Did You Feel It?*" reporting system.
3. Within 25 business days (five weeks) of change in operating state.
4. Onset of damage is defined as cosmetic damage to structures – such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves and cabinet.

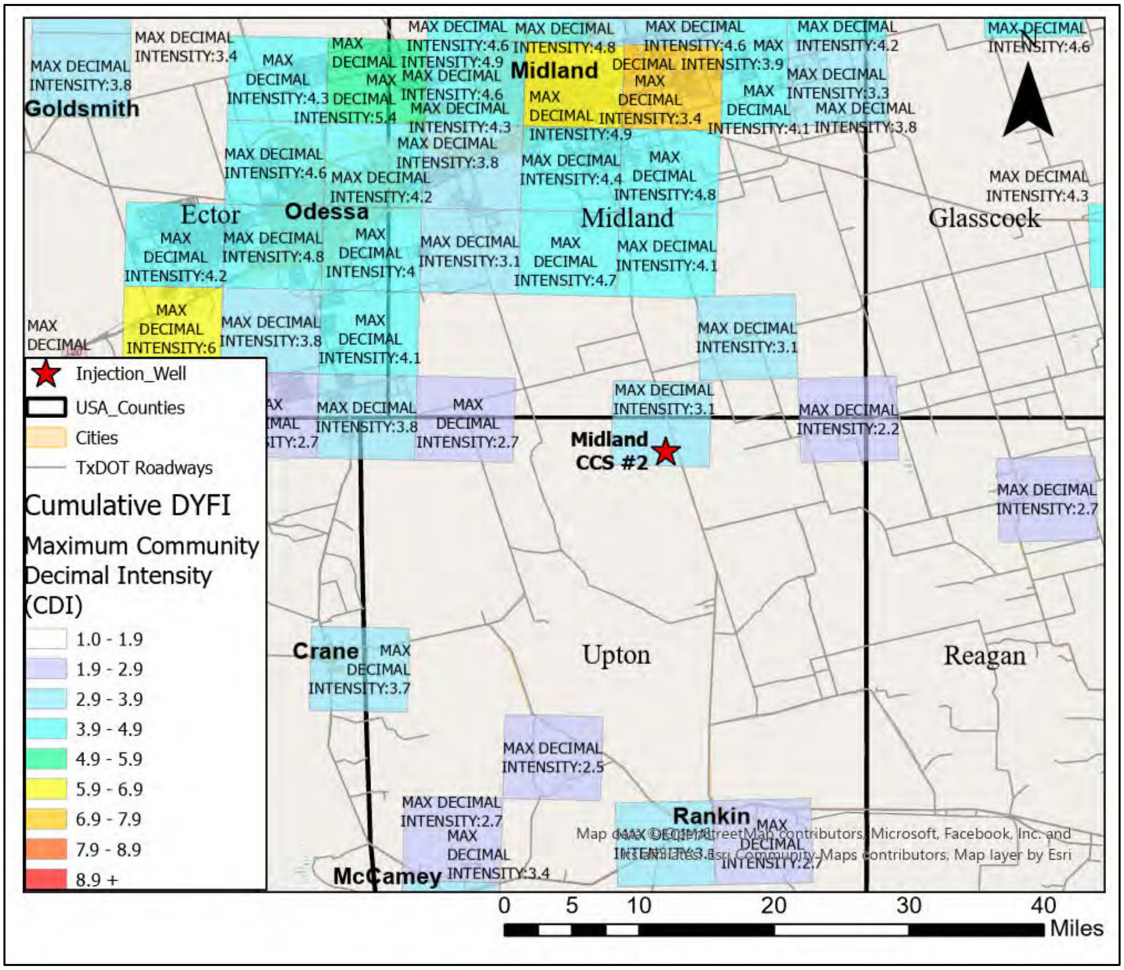


Figure 10-3: "Did you Feel It" Internet-based Macroseismic Intensity Map for Upton County
Data is Cumulative from the year 2001 to present. DYFI polygon at the well location has a max decimal intensity of 3.1

10.2.6.1 Did you Feel It Analysis

The "Did You Feel It" (DYFI) internet-based macroseismic intensity map in **Figure 10-3** shows the proposed injection well location has a value of M3.1. This supports Milestone's proposed seismicity operational states alert status of M2.5-3.0 (orange) and higher response categories of M3.0+ (magenta) and M3.5+ (red). Given that there have been events in the M2.0-M2.5 (Yellow) range historically, this will permit the Milestone site to continue to operate if baseline seismicity occurs, but not if elevated levels of seismicity begin to happen. Milestone selected these ranges based on the observed DYFI reports in the area for the last twenty-four (24) years in addition to other historical seismicity data. Please review historical seismicity sections of permit **Section 1** and **Section 6** for additional information.

10.3 Response Personnel and Equipment

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

Milestone health and safety professionals will make appropriate emergency response equipment available for probable events, this may include the following: SCBA breathing equipment, electric vehicles, personal CO_2 monitors and other personal protective equipment.

10.4 Emergency Communication Plan

As appropriate, if related to health and safety, Milestone's director of health and safety, [redacted], or if environmentally related, Milestone's Vice President of Sustainability and Communications, [redacted] will communicate with the public and first responders regarding events that require an emergency response, including the impact of the event on drinking water, potential atmospheric releases or the severity of the event, actions taken or planned, etc. Milestone's manager of Regulatory and Environmental Compliance, [redacted], will communicate with EPA Region 6, TCEQ and RRC officials regarding regulatory matters.

Milestone will also communicate with other entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, Oil and Gas Operators and Regional Response Teams (as part of the National Response Team).

Additionally, prior to the commencement of CO_2 injection operations, Milestone, via Milestone's Sr. Land Manager, [redacted] will communicate in writing with landowners residing/living adjacent to the storage site to provide a summary of the information contained within this ERRP, including but not limited to information about the nature of the operations, size of the AoR, hazards and characteristics of injectate, operator contact list, potential risks, and possible response approaches.

An emergency contact list (**Table 10-9**) will be maintained during the life of the project and posted at all Milestone Carbon facilities. In the unlikely occurrence of an emergency event, the director of operations or a field superintendent will immediately start the contact list and ensure that responsible, essential Milestone and local emergency personnel are contacted. The operator's designated personnel will handle all event communications with the public. A list of contractors (**Table 10-10**) will be maintained during the life of the project.

The appropriate amount of information, timing, and communications method(s) will be based upon the circumstances and severity of the event, which may include, but are not limited to:

1) Event description and location.
2) Event investigation process and response status (e.g., actions taken).
3) Whether there is any known impact to the drinking water, surface atmospheric release of CO_2 or other environmental impacts
4) Any known injury to person or property or probable risk to person or property.

For protracted responses (e.g., passive monitoring or ongoing cleanups), the project will provide periodic updates on the progress of the response action(s). Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. Site personnel to be notified (not listed in order of notification):

Table 10-9: Contact Information for Key Local, State and Other Authorities

Agency	Phone Number
Upton County Sheriff's Office	432-693-2422
Upton County Emergency Management Department	432-693-2321 ext. 2
Upton County 911 Coordinator	432-693-2014
Texas State Police	512- 424-2000 (HQ, Austin) 432-498-2140, Midland
Texas Dept. of Public Safety 24-hour non-Emergency	800-525-5555
Texas Dept. of Transportation	800-558-9368
Local Midkiff Volunteer Fire Department	PO Box 130, Midkiff, TX 79755
Midland Fire Department	432-685-7332
Angel MedFlight – advanced air transport-DOT and FAA provider	855-827-8890
Texas Division of Emergency Management agency:	512-424-2208
Texas Commission of Environmental Quality / Water Division:	512-239-6696
The Railroad Commission of Texas 24-Hour Emergency reporting line	844-773-0305 (toll free) or 512-463-6788
UIC Texas Program Director:	512-239-6466
EPA National Response Center (24 hours)	800-424-8802
EPA Region 6 (South Central, *serving AR, LA, OK, and TX)* Customer Service Hot Line	toll-free line - 800-887-6063; Outside Region 6 call 214-665-2760
Milestone Environmental South Midland Facility Emergency Hotline	432-305-4360
Rankin County Hospital District	432-693-1200
Midland Memorial Hospital	432-221-1111

Table 10-10: Potential Contractor and Service Providers

Agency	Phone Number
Permian Paving | Excavation and Dirt Work / Hauling	432-214-2317
Midland County Emergency Management | Temporary Housing & Rentals	432-688-4160
Schlumberger Cementing	720-272-5288
Schlumberger Core Analysis	801-232-5799
Schlumberger Direction & Measurements	484-522-8434
Schlumberger Products & Services	517-755-9050
Schlumberger Bits	517-755-9050
Schlumberger Completions	440-391-2711
MI SWACO Drilling Fluids	661-549-3645
Hazardous Waste Disposal in Midland Texas	708-263-0756

10.5 Plan Review [40 CFR 146.94(d)]

This ERRP will be reviewed and updated at least once every five (5) years. Any amendments to the plan will be approved by the UIC Program Director and will be incorporated into the permit. This plan will also be reviewed and re-submitted to the UIC Program Director given the following:

- Within one (1) year of an AoR re-evaluation
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by UIC Program Director
- Change in key personnel
- Or when required by the UIC Program Director.

If the review indicates that no amendments to the ERRP are necessary, Milestone will provide the UIC Program Director 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 UIC Program Director within sixty (60) days following an event that initiates the ERRP review procedure.

10.6 Staff Training and Exercise Procedures

Personnel responsible for implementing this ERRP will be trained in their duties and responsibilities during annual onsite and/or table-top training exercises. All Milestone personnel, visitors, and contractors must attend an overview orientation before obtaining permission to enter any of the facilities. A refresher course on this training will be required annually.

Before starting CO_2 injection operations, Milestone will provide a copy of the ERRP to local first responders and discuss potential response scenarios. Milestone will proactively work with local first responders to determine appropriate procedures in the event of an emergency event including removing the public from the affected area or controlling access to the site. These procedures will include the use of specialty equipment. The Milestone incident commander will work with first responders on the scene to direct what responses are required on location, e.g. fire suppression, evacuation of injured personnel, access to the location.

10.7 Site Security and Access Control

Milestone will control access to the well facilities and any associated surface infrastructure such as SCADA control panels or surface pumps. A fence will be built around the site with locked gates. All panels that do not contain emergency stops will be locked.

Security cameras and motion detectors will be installed at the facility to alert Milestone personnel of any unauthorized activity. These will be monitored 24/7 by a commercial alarm company that operates in the area. There will be Milestone staff on site 24/7 at the Milestone Environmental services office.

10.8 Resume Operations [40 CFR 146.94(c)]

If the injection wells are shut-in or suspended for an emergency event, after all events have been declared resolved, Milestone will restart injection operations after demonstrating the injection operations will not endanger the underground sources of drinking water (USDW).

If remediation is required Milestone will submit a remediation plan within (30) thirty days of such notice from the UIC Director. This plan will include follow-up monitoring and testing regarding the emergency event.

Milestone will submit a notice of intent to resume injection to the Director at least five (5) business days before injection is to resume if there are no remaining events and no endangerment of USDW. Injection operations will only resume upon receipt of written authorization of the UIC Program Director.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment I: Post-Injection Site Care and Site Closure Plan

[40 CFR §146.93]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

MILESTONE CARBON

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Prepared by

Numeric Solutions, LLC

1536 Eastman Ave, Suite D

Ventura, California 93003

Updated 14 January 2026

Table of Contents

List of Tables

List of Figures

9.0 POST-INJECTION SITE CARE & SITE CLOSURE PLAN [40 CFR 146.82(a)(17), 146.93(a)]

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Milestone, the operator of South Midland Facility, will perform to meet the requirements of 40 CFR 146.93. Milestone will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years. Furthermore, Milestone may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b) (3). Following approval for site closure, Milestone will plug all monitoring wells and submit a *Site Closure Report* and associated documentation.

Please note - Milestone is ***not*** applying for an Alternative Post Site Injection Care Timeline.

9.1 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

The formation pressure at the Injection Well is predicted to decline rapidly within the first four (4) years following cessation of injection. Based on the modeling of the pressure front as part of the AoR delineation, pressure is expected to decrease to less than 135 psi above pre-injection levels by the end of the PISC (50-year) timeframe.

The maximum predicted injection pressure differential in the wellbore over the life of the project is 1,812 psi over pre-injection levels. The maximum predicted injection pressure differential in the reservoir is 1,594 psi over pre-injection levels. Both pressures occur within one (1) year after the start of injection, likely due to relative permeability effects. Additional information on the projected post-injection pressure declines and differentials is presented in the plume modeling and the Area of Review and Corrective Action Plan, **Sections 2.**

9.2 CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 9-1 shows the predicted extent of the plume and pressure front at the end of the 50-year PISC timeframe (model year-2089), representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results, pursuant to 40 CFR 146.84.

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

Performing groundwater quality monitoring and plume and pressure front tracking as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days of the anniversary date of the date on which injection ceases, as described under “Schedule for Submitting Post-Injection Monitoring Results,” herein.

Groundwater monitoring will be conducted using the NSSW #1-5, USDW #2 and IZM #2 monitoring wells, as well as the Well. The NSSW wells penetrate the Edwards-Trinity Plateau aquifer at approximately 250 feet. The USDW #2 is a shallow monitoring well that targets the deepest recorded USDW zone, the Dockum aquifer base, located approximately 1,250 feet below the surface. The IZM #2 is a deep In-Zone Monitoring Well that penetrates to the Siluro-Devonian and Ellenburger. All of the monitoring wells are located on Milestone leasehold near roads, so access to the monitoring wells will be guaranteed.

A description of direct and indirect monitoring is covered in **Section 6**. A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the **Appendix C** to the Testing and Monitoring Plan.

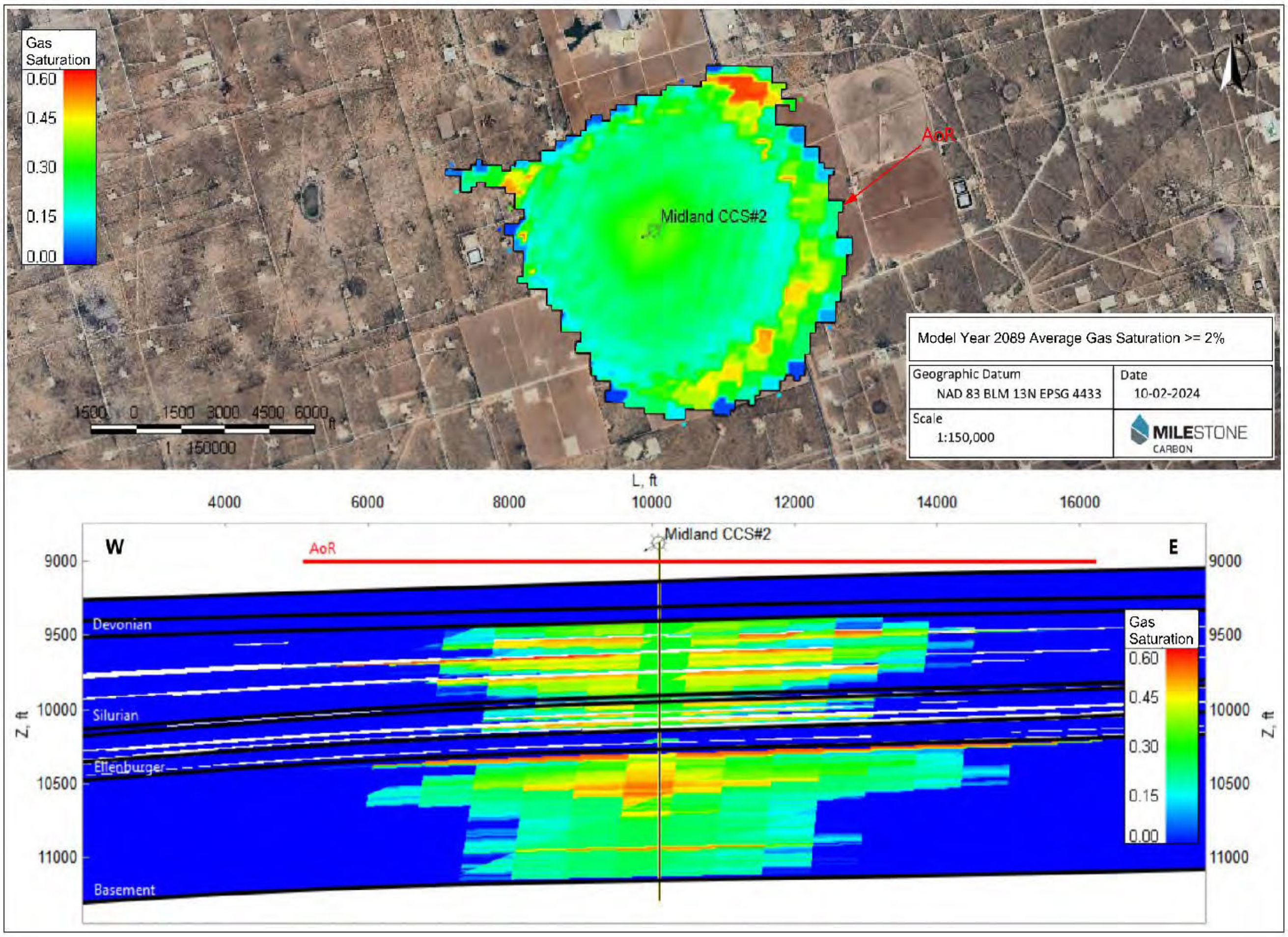


Figure 9-1: Map of the predicted extent of the CO_2 plume 50 years post-closure
Map of the predicted extent of the CO_2 plume at site of closure 50 years after the cessation of injection model year 2089.

9.4 Monitoring Above Confining Zone [40 CFR 146.93(a)(2)(iii)]

9.4.1 Ground Water Testing Frequency

Tables 9-1 and **9-2** present the planned direct and indirect monitoring methods, locations, and frequencies for monitoring of groundwater quality and geochemical changes above the confining zone, in USDW zone, and Pennsylvanian section after injection ceases. **Figure 9-2** shows the locations of the monitoring wells. Continuous monitoring data will be measured at 5-second frequency and recorded at 5-minute intervals unless otherwise specified.

As noted in **Section 6,** the Midland USDW #2 and Midland NSSW #1-5 will be installed with pH and electrical conductivity (EC) water probes for continuous measurement of these properties.

Water sampling and analysis will occur at the end of injection and then annually thereafter until year 10 when sampling and analysis will transition to every five (5) years. Sampling and monitoring will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director.

Logging surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director.

Milestone will also employ fiber-optic cable measuring DTS and DAS/DSS to monitor for leakage and pressure directly from the Midland CCS#2 and IZM #2. Milestone will measure DTS continuously and DAS/DSS annually for the first ten (10) years, then every five (5) years thereafter or until the fiberoptic cable fails. The expected lifetime of fiberoptic cable is only approximately 15-20 years as described in **Appendix C** (QASP). The QASP includes a description of the groundwater sampling methods, sample handling and custody protocols and quality control.

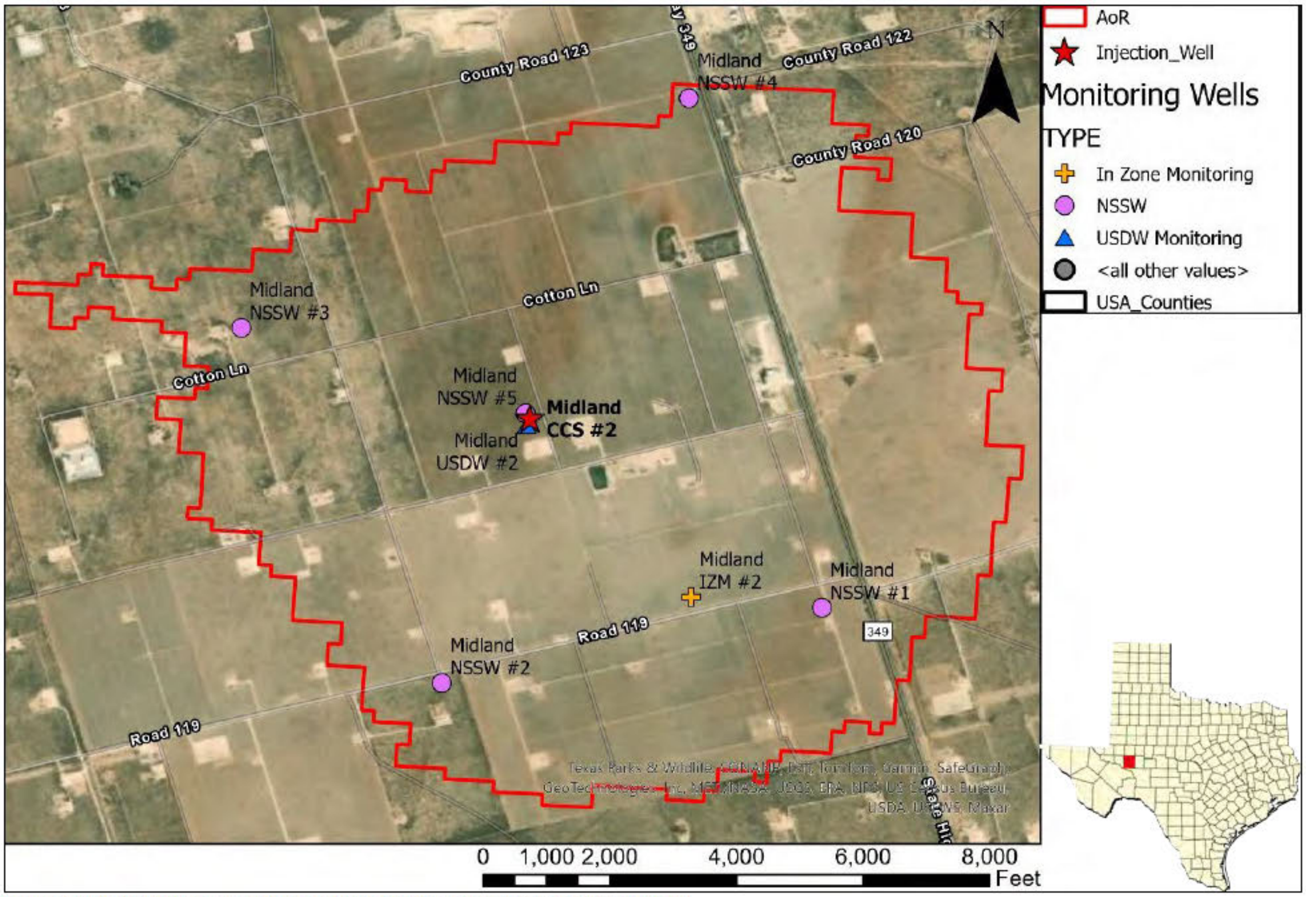


Figure 9-2: Shallow and Deep Monitoring Wells Location Map

Table 9-1: Post-Injection Direct Groundwater and Geochemical Changes Monitoring Above Confining Zone

Target Formation	Monitoring Activity	Locations	Frequency			
			1st Quarter Post Injection	Year 2-5	Year 5-10	Year 10-50
Edwards-Trinity (Plateau)	Fluid Sampling	NSSW #1-6	Within three (3) months of cessation of Injection	Annual	Annual	Every 5 Years
	pH and EC			Continuous		
Dockum	Fluid Sampling	USDW #2	Within three (3) months of cessation of Injection	Annual		
	pH and EC			Continuous		
Pennsylvanian	U-tube Fluid Sampling	IZM #2; and CCS #2 if possible	Within three (3) months of cessation of Injection	Annual		
	DAS/DSS Pressure/Strain			Annual		
	DTS Temperature			Continuous		

Table 9-2: Post-Injection Indirect Groundwater and Groundwater Changes Monitoring Above the Confining Zone

Target Formation	Monitoring Activity	Locations	Frequency		
			1st Quarter Post Injection	Year 2-10	Year 10-50
Pennsylvanian	Pulse Neutron Logging	IZM #2; CCS #2 If Not Plugged	Within three (3) months of cessation of injection	Annual	Every 5 years

9.4.2 Ground Water Testing Matrix

Table 9-3 identifies the parameters to be monitored, and the analytical methods Milestone will employ to analyze groundwater samples taken from any depth. The table is organized based on interval. Sampling will be performed as described in permit **Section 13 Appendix C** (QASP). The QASP includes a description of the groundwater sampling methods, sample handling and custody protocols and quality control.

In general, Milestone will analyze all water samples for cations, anions, dissolved CO_2, total dissolved solids, alkalinity, pH, specific conductance and temperature.

In deeper intervals, not within the USDW, if dissolved CO_2 is detected above baseline levels, isotopic analysis will be undertaken to attempt to verify the origin. Further the water density will be tested for deeper samples.

9.4.3 Sampling and Analytical Methods

Fluid samples in NSSW wells and USDW monitoring wells will be collected at the monitored formation temperatures and maintained at the formation pressures within a pressurized sample container to prevent any losses of dissolved gases. Prior to sampling, the well will be purged of any fluid stored in the wellbore. Static fluid level and temperature will be measured prior to purging the well. A U-tube sampling system will be lowered to the monitored zone via wireline or slickline and the rate of sample collection should not exceed the rate at which the well was purged.

For In-zone Monitoring well, a permanent U-tube sampling system will be installed within the annulus and used to sample the brine above the Top Seal.

Water samples will be tested, and results maintained for the parameters listed above. If any impurities exist in the injectate, they should also be tested within the groundwater samples to detect any concentrations beyond the baseline. Results from the samples will be maintained in an electronic database. All samples will be individually numbered, and EPA/TCEQ best practices will be used.

9.4.4 Laboratory Chain of Custody Procedures

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records will be maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

9.4.5 Quality Assurance and Surveillance Measures [40 CFR 146.90(k)]

Water samples will be sent to a third-party commercial water testing laboratory. Standard chain-of-custody procedures will be followed, and records maintained to allow a full reconstruction of how the samples were collected, stored and transported, including any problems encountered.

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

Parameters	Analytical Methods [1]
USDW (Edwards-Trinity (Plateau) and Dockum)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Above Confining Zone (Pennsylvanian)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, HCO_3 and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

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

9.5 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

9.5.1 Direct and Indirect Monitoring of Plume and Pressure

Milestone will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. **Table 9-4** presents the direct and indirect methods to monitor the *CO_2 plume* after injection ceases, including the activities, locations, and frequencies to be employed. **Table 9-6** presents the direct and indirect methods used to monitor *CO_2 pressure* after injection ceases.

Direct methods that Milestone will employ are water sampling from the two (2) U-tube systems within the injection interval of the In-Zone Monitoring well. Milestone will sample the Midland CCS #2 and if it is not plugged via a U-tube sampling system lowered on wireline. Milestone will sample the injection interval annually for the first ten (10) years then every five (5) years thereafter. The parameters to be analyzed as part of fluid sampling (and associated analytical methods) are presented in **Table 9-5**. Milestone will also employ fiber-optic cable measuring DTS and DAS/DSS to monitor for leakage and pressure directly from the CCS #2 and IZM #2. Milestone will measure DTS continuously and DAS/DSS annually for the first ten (10) years, then every five (5) years thereafter or until the fiberoptic cable fails. The expected lifetime of fiberoptic cable is only approximately 15-20 years from installation during construction.

Indirect monitoring activities will include pulse neutron logging, electromagnetic (CSEM) surveys, Microseismic surveys, passive seismicity and computational modeling. See permit **Section 6** for more discussion on these techniques. Milestone will undertake pulse neutron logging annually for the first ten (10) years post injection cessation, then transition to every five (5) years thereafter. Milestone will conduct geophysical surveys in year 1, then in years that are prime numbers, years 2,3,5,7 and then discontinue thereafter.

Geophysical surveys may include one or more of the following surface-based indirect measurements:

- Electromagnetic (CSEM) surveys
- Passive Microseismic Surveys
- Other geophysical techniques developed by Milestone during the injection period that have been shown to be effective at indirectly measuring plume and pressure fronts.

Fluid sampling and wireline logging will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the UIC Program Director. Geophysical surveys will be performed in the 4th quarter before, or the 1st quarter of, the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.

Passive seismic monitoring using five (5) near surface seismic stations (NSSW Wells) to detect local events over M 1.0 within the AoR will be measured by Milestone after injection ceases. Passive seismic data will be monitored continuously at 200 Hz, 5 millisecond frequency. Seismicity data will be reported annually unless an event of 2.5 or greater occurs within 10km of the injection wells.

Following the end of injection, the plume is expected to grow slightly as CO2 rises with gravity. Computational modelling throughout the injection period calibrated by recorded data and history matching the injection rates and pressures will be used to further predict the movement of the plume. The CO2 plume measured by geophysical surveys will be integrated into the post-injection dynamic modeling to validate the predicted rate of change in the plume size. Modeling will be updated after new surface geophysical measurements are made.

Table 9-4: Post-Injection Plume Monitoring

Target Formation	Monitoring Activity	Location(s)	Frequency		
			1st Quarter Post Injection	Years 2-10	Years 10-50
Direct Plume Monitoring					
Siluro-Devonian and Ellenburger	Fluid sampling	IZM #2; CCS #2 if not plugged	Within 3 Months of Injection Cessation	Annual	Every 5 Years
IZM #2 – Surface to Basement; CCS #2- Surface to Base of Top-Seal	Leakage Detection DTS Temperature	IZM #2, CCS #2	Continuous Until Fiberoptic Cable Fails		
Indirect Plume Monitoring					
1000ft above Top-Seal, Top-Seal, and Injection Interval	Pulse Neutron Logging	IZM #2; CCS #2 if not plugged	Within 3 Months of Injection Cessation	Annual	Every 5 Years
Surface to Basement	Geophysical Survey(s)	AoR	Within 3 Months of Injection Cessation	Years that are Prime Numbers; Years 2, 3, 5, 7	None
Surface to Basement	Passive Seismicity	AoR	Continuous Until Equipment Fails		
Entire Injection Interval	Computational Modelling Updates	AoR	After Geophysical Surveys		Every 5 years

Table 9-5: Summary of Analytical and Field Parameters for Fluid Sampling

Parameters	Analytical Methods [1]
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, HCO_3 and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density(field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

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

Table 9-6: Post-Injection Pressure Front Monitoring

Target Formation	Monitoring Activity	Locations		Frequency		
				1st Quarter Post Injection	Years 2-10	Years 10-50
Direct Pressure Front Monitoring						
Entire Injection Interval	DAS/DSS Pressure/Strain	IZM #2; CCS #2 if possible	Within 3 Months of Injection Cessation	Annual Or Until Fiberoptic Cable Fails		Every 5 Years if Cable Usable
Indirect or Ancillary Pressure Front Monitoring						
Entire Injection Interval	DTS Temperature	IZM #2; CCS #2 if possible		Continuous Until Fiberoptic Cable Fails		
Surface to Basement	Microseismic Survey & other Geophysical Surveys	AoR		Within 3 Months of Injection Cessation	Years that are Prime Numbers; Years 2, 3, 5, 7	None

9.5.2 Plume Predictions at Various Time Stamps

Predicted plume geometry relative to the injection well at various time steps post injection is shown in **Figures 9-3** through **9-7**. Changes in plume geometry over the Injection phase, year 2027-2039, are covered in permit **Section 2**.

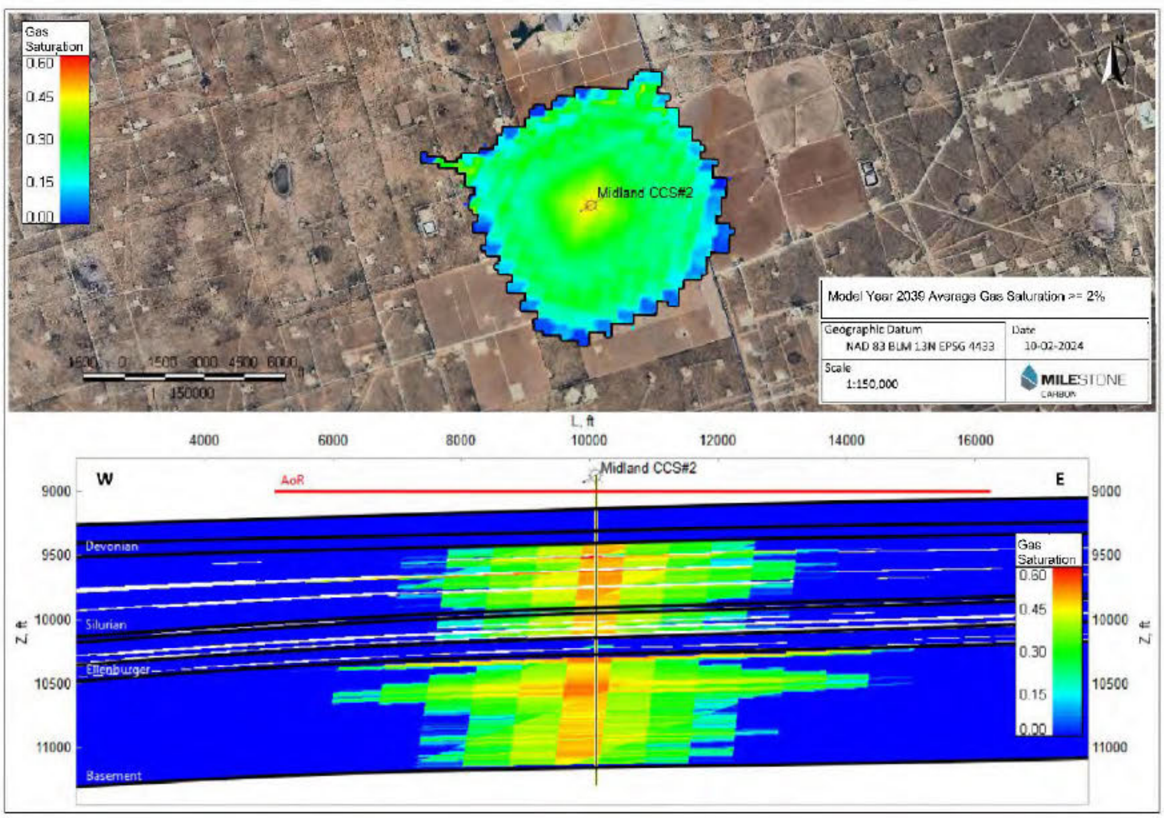


Figure 9-3: Predicted extent of the CO_2 plume – year 2039 – Start of PISC Period
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of the injection period, model year 2039.

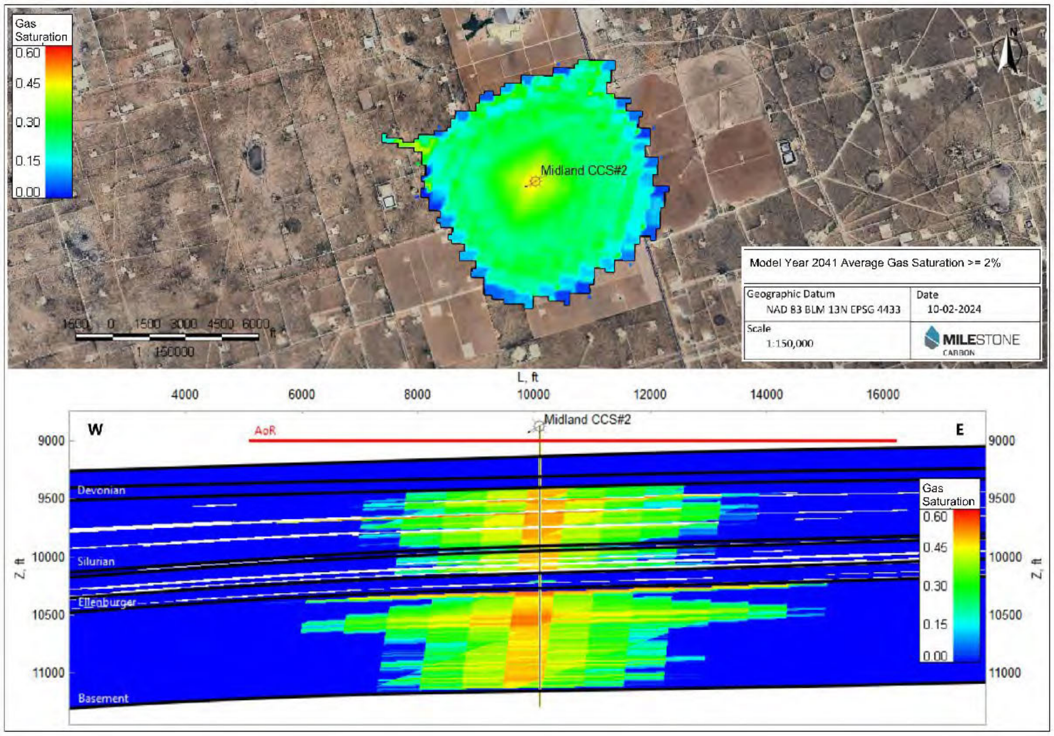


Figure 9-4: Predicted extent of the CO_2 plume – year 2041
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations 3 years after cessation of injection – modeled year 2041.

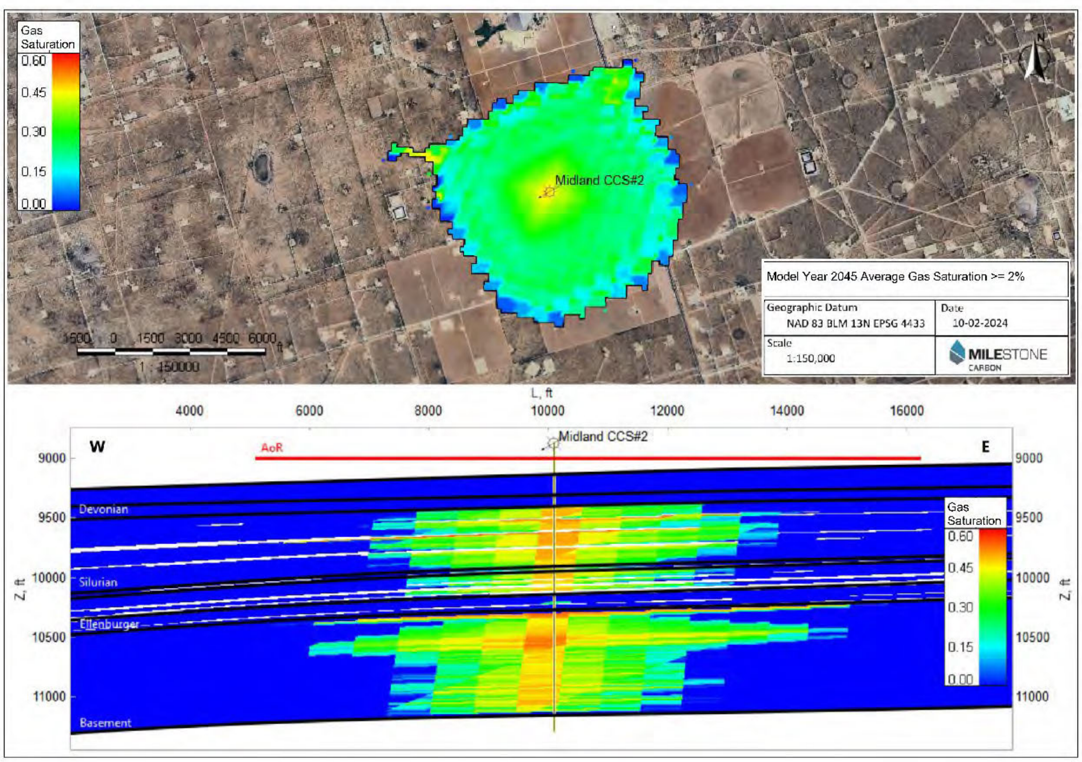


Figure 9-5: Predicted extent of the CO2 plume - est. year 2045
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of 8 years after the cessation of injection – estimated year 2045

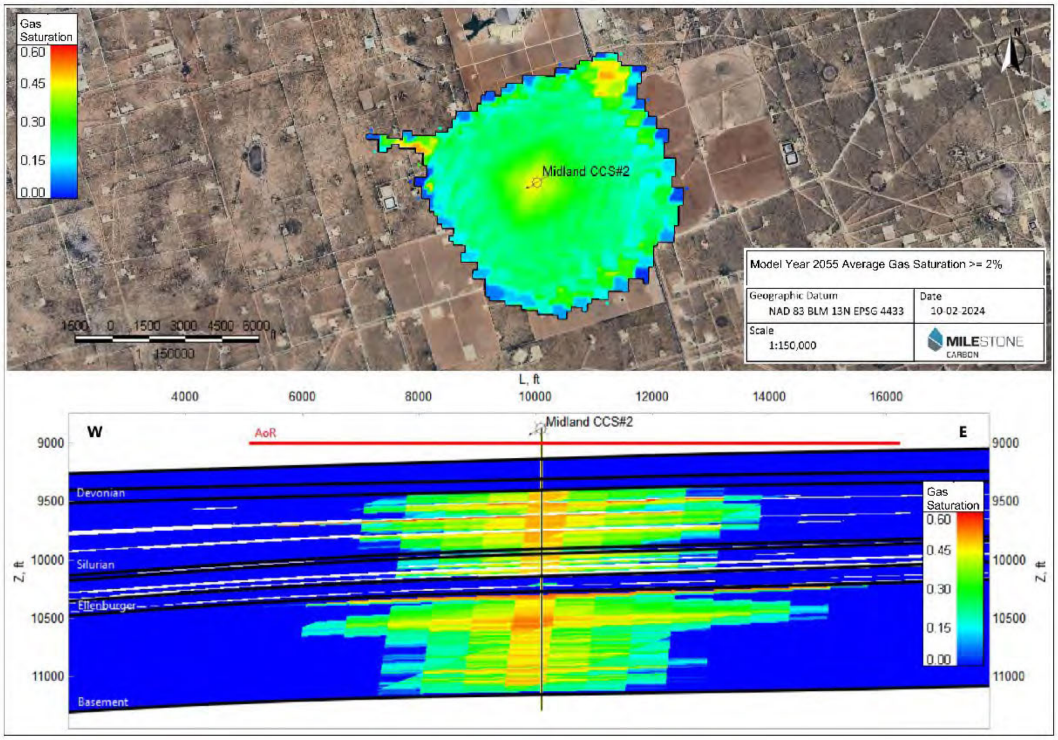


Figure 9-6: Predicted extent of the CO_2 plume - est. year 2055 (site closure)
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations at the end of 18 years after the cessation of injection (predicted time of site closure) – estimated year 2055

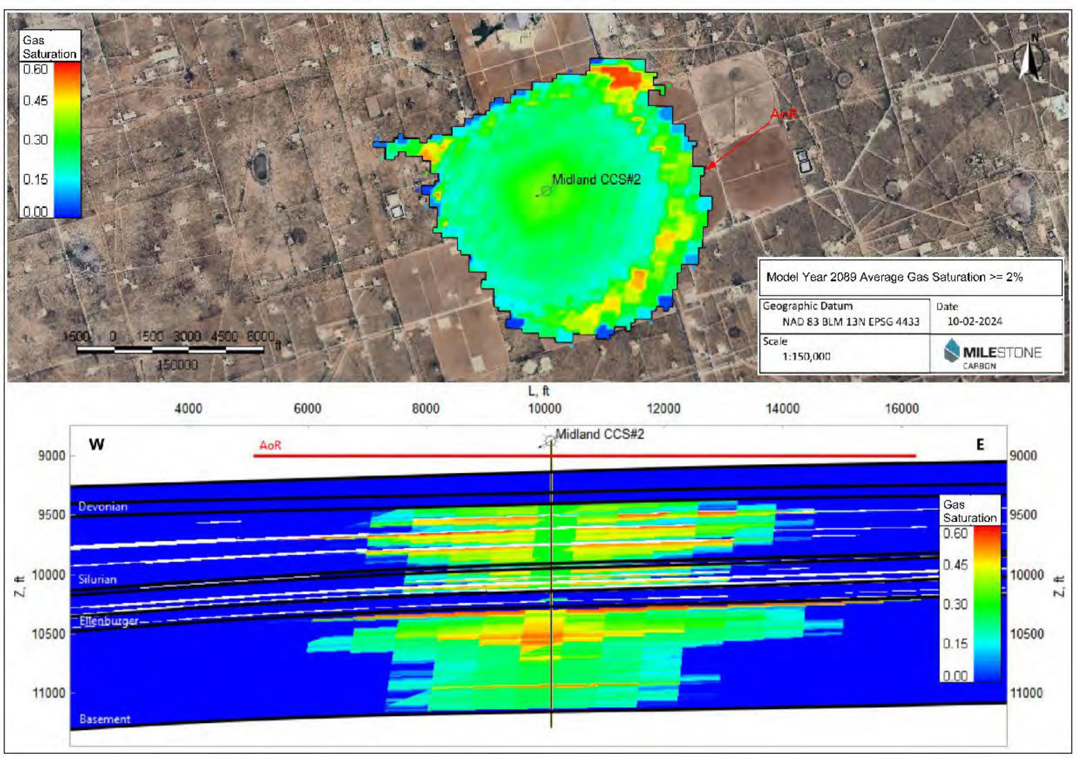


Figure 9-7: Predicted extent of the CO_2 plume – est. year 2089 – End of PISC Period
Map of the predicted extent of the CO_2 plume and pressure front relative to monitoring locations 50 years after the cessation of injection – estimated year 2089

9.5.3 Pressure and Phase Predictions

Predicted pressure profiles at the surface and bottomhole pressure at the injection wells for 50 years after the cessation of injection are shown in **Figures 9-8**. The bottomhole pressure reference depth is at the top of the injection interval. The predicted amount of CO_2 in the mobile gas, trapped gas, and dissolved (aqueous) phases for 50 years after the cessation of injection is in **Figure 9-9**. The maximum incremental well bottomhole pressure in the reservoir for the Midland CCS #2 is 1,598 psi. The pressure decays rapidly to less than 200 psi above the initial pressure within 5 years of the end of injection. Initial pressure for the Midland CCS #2 is 5,491 psi in the reservoir at the top of the Injection interval.

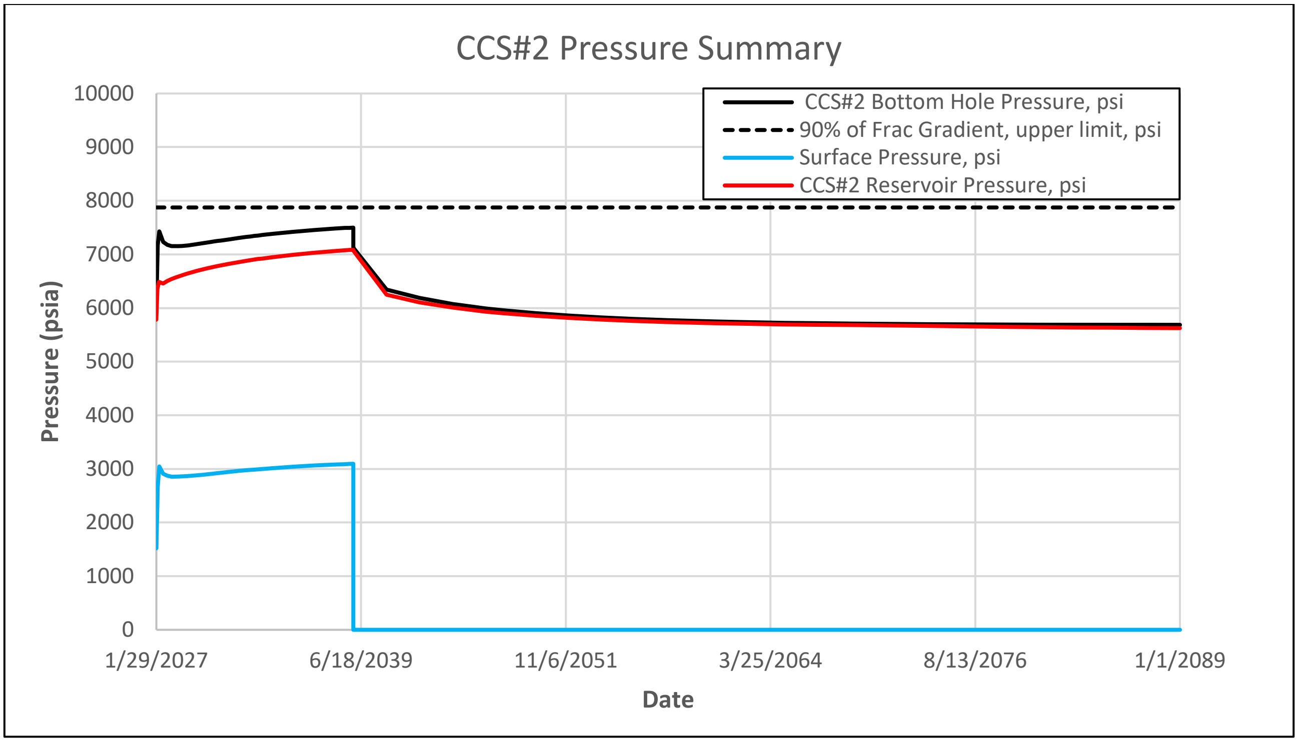


Figure 9-8: Predicted pressure profile from start-up until 50 years after cessation of injection

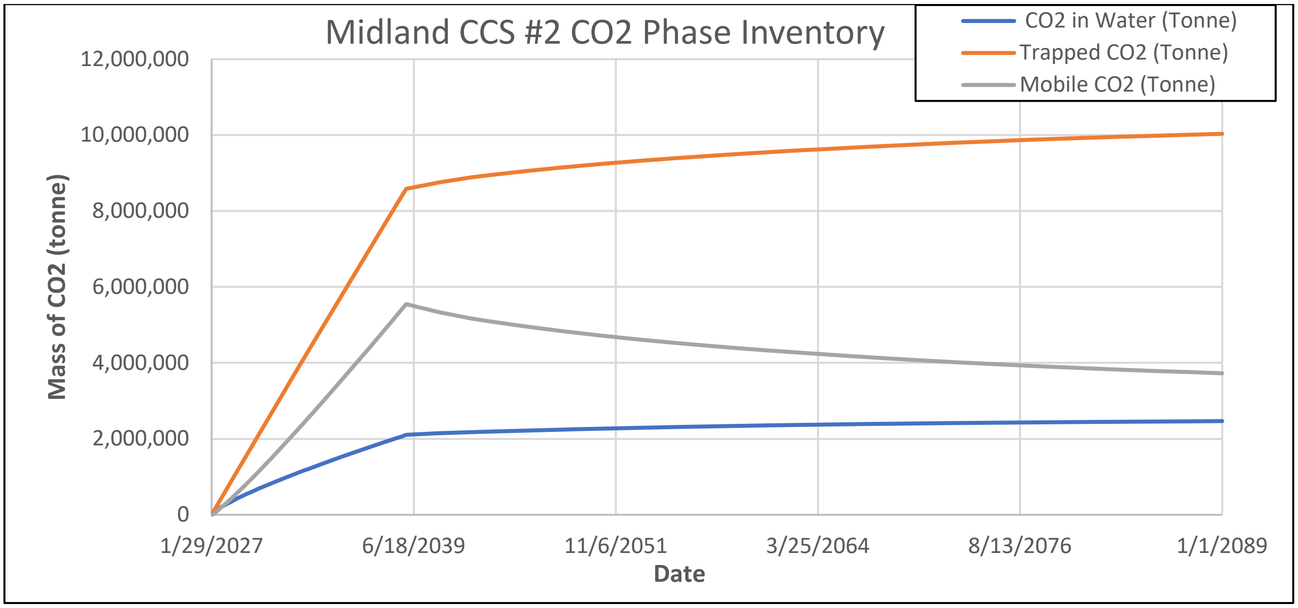


Figure 9-9: Predicted phase distribution from start-up until 50 years after cessation of injection

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

Results of the latest monitoring data will be submitted annually within 60 days of the anniversary date of the cessation of injection. Any amendments to the post site injection care and monitoring plan will be submitted and if approved by the UIC Program Director, will be incorporated into the permit. This plan will also be reviewed and submitted to the UIC Program Director within six months of an area of review evaluation event (see **Section 2**), any significant emergency event (**see Section 10**), following any significant changes to the facility, such as addition of injection or monitoring wells; changes in injection rate; or when required by the UIC Program Director. From years 10 to 50 after cessation of injection, reporting frequency will decrease to every 5 years if no anomalous activity has been detected within the preceding 10 years.

If the review indicates that no amendments to the post site care plan or monitoring strategy are necessary, Milestone will provide the permitting agency with the documentation supporting the "no amendment necessary" determination at least annually within 60 days of the anniversary of the date of cessation of injection.

9.7 Duration of Post Site Injection Care and Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(a)(2)(v)]

Milestone is **not** applying for an alternative post-injection site care timeframe at this time. The duration of the post site injection care (PISC) will be 50 years from the cessation of injection operations.

9.8 Non-Endangerment Demonstration Criteria [40 CFR 146.93(b)]

Prior to approval of the end of the post-injection phase, Milestone will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3). The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

9.8.1 Introduction and Overview

A summary of relevant background information will be provided, 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.

9.8.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan of this permit and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. 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 all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization 40 CFR 146.82(a)(6) and 146.87(d)(3).

9.8.3 Computational Modeling Calibration and Validation

A series of data sources detailed in **Section 6** will be used to update the computational model at least once every 5 years, if not more frequently. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- Temperature and pressure data
- Pulse Neutron Logging
- Geophysical Surveys
- Injection surface pressure and downhole pressure

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. Post Injection data will include historical injection rates, pressures, pressure fall-off, historical operational parameters of the Midland CCS #2 Well that will inform the dynamic model. History matching the dynamic model to measured data, where recorded data is used as an input to the dynamic model and the input parameters adjusted to match the recorded pressures will be performed by Milestone. By history matching the recorded data, calibration and validation of the model to recorded data will be established. History matching the Midland CCS #2 Well, and any offset injection at the Davidson Unit #1 saltwater disposal (SWD), Clay Henry SWD, Midkiff #1 SWD and any new SWD wells, will continue to inform the dynamic simulation.

9.8.4 Evaluation of Reservoir Pressure

The extent of the pressure front will be evaluated using surface and bottomhole pressure gauges from the injection well, and In-zone monitoring well. Reported pressures from the offset SWD wells that are reported to the RRC will also be utilized. This information will be history matched in the dynamic model at least once every 5 years, and more frequently if there is major disagreement. If no valid solution can be found, Milestone may perform additional testing to attempt to reconcile measured vs modeled data.

9.8.5 Evaluation of Carbon Dioxide Plume

Remote sensing techniques detailed in **Section 6** will be used to monitor the aerial and vertical extent of the CO_2 plume. These may include the following:

- Temperature and pressure data
- Pulse Neutron Logging
- EM Surveys
- Microseismic

This information will be compared to the model predictions to attempt to match modeled pressure, gas saturation and vertical/aerial extent to measured values.

9.8.6 Evaluation of Emergencies or Other Events

Water testing noted in **Section 6** will be used to demonstrate that USDWs are not impacted by injection activities. Deviation from water measurements taken by Milestone prior to the start of injection will indicate that the USDW is potentially being impacted. Seasonal variation will be considered when analyzing for deviation.

Artificial penetrations of the reservoir are noted in **Section 1**. There are **zero** artificial penetrations of the injection interval within the AoR. If any subsequent artificial penetrations are discovered, they will be remediated with proper CRA material and soil testing as detailed in permit **Section 6** and subsequent testing will be performed annually to verify no leakages within the hypothetical plugged wellbores.

9.9 Site Closure Plan [146.93 (d) – (h)]

Milestone will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described herein. Milestone will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior to its intent to close the site. Once the permitting agency has approved closure of the site, Milestone will plug the all the monitoring wells to restore the site and move out all equipment; and submit a site closure report to the UIC Program Director. The activities, as described below, represent the planned activities. 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.

9.9.1 Plugging Monitoring Well(s)

Plugging of the injection well will be completed in accordance with procedures in **Section 8**. Plugging of the in-zone monitoring and USDW monitoring wells will be conducted according to procedures herein.

After injection in the injection well ceases and after the appropriate post-injection monitoring period is complete, the in-zone monitoring and USDW monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR 146.92 and all state and local regulations. The plugging procedure and materials will be designed to prevent any unwanted fluid movement and to protect any USDWs. Prior to plugging the wells, any 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, the wells will be wireline 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 plugging procedures are presented herein. All casing in these wells will be cemented to surface at the time of construction and will not be retrievable at abandonment. A combination of bridge plugs and cement plugs will be set to plug the wells.

All casing strings will be cut at least three (3) feet below ground level. A steel plate, with the required permit information, will be welded to the top of the casing.

9.9.2 Plugging the In-Zone Monitoring Well

Notification, regulatory and plugging procedures will include:

9.9.2.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) Bottomhole reservoir pressure will be measured using the downhole pressure gauge.
3) Retrieve downhole pressure gauge and geophone.
4) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
5) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.
6) The wellbore will be displaced with a kill weight fluid, 9 ppg minimum.

9.9.2.2 Plugging Activities

1) Position workstring at 13,780 feet and pump a 1,580-foot balanced corrosion resistant cement plug from TD to 12,205 feet.
2) Wait on cement, tag and pressure test the corrosion resistant cement plug.
3) If the corrosion resistant cement plug is tagged deeper than planned, an additional cement plug will be set up to 12,205 feet.

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4) Pull out of hole and make up a corrosion resistant bridge plug.
5) Run CRA bridge plug and set with workstring in the Woodford shale at 12,160 feet.
    a. Tag and pressure test bridge plug.
6) Position workstring to bridge plug at 12,160 feet and pump a 300-foot corrosion resistant cement plug across the Woodford from 12,160 feet to 11,860 feet.
7) Wait on cement, tag and pressure test the corrosion resistant cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,860 feet.
8) Position workstring at 11,551 feet and pump a 200-foot balanced corrosion resistant cement plug across the Atoka top from 11,551 feet to 11,351 feet.
9) Wait on cement, tag and pressure test the cement plug.
10) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 11,351 feet.
11) Position workstring at 10,891 feet and pump a 200-foot balanced corrosion resistant cement plug across the Strawn top from 10,891 feet to 10,691 feet.
12) Wait on cement, tag and pressure test the cement plug.
13) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 10,691 feet.
14) Position workstring at 9,192 feet and pump a 200-foot balanced corrosion resistant cement plug across the Wolfcamp top and intermediate casing shoe from 9,192 feet to ,900 feet.
15) Position workstring at 7,700 feet and pump a 200-foot balanced corrosion resistant cement plug across the Sprayberry top from 7,700 feet to 7,500 feet.
16) Wait on cement, tag and pressure test the cement plug.
17) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 7,500 feet.
18) Position workstring at 4,208 feet and pump a 200-foot balanced corrosion resistant cement plug across the San Andres top from 4,208 feet to 4,008 feet.
19) Wait on cement, tag and pressure test the cement plug.
20) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 4,008 feet.
21) Pull out of hole and make up a corrosion resistant bridge plug.
22) Run CRA bridge plug and set with workstring at 1,350 feet.
    a. Tag and pressure test bridge plug.
23) Pump a 50-foot corrosion resistant cement plug across the surface casing shoe and USDW from 1,300 ft to 1,250 feet.
24) Wait on cement, tag and pressure test the cement plug.
    a. If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 1,250 feet.
25) Position workstring at 400 feet and pump a 100-foot balanced corrosion resistant cement plug from 400 feet to 300 feet.
26) Wait on cement, tag and pressure test the cement plug.
27) If the cement plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 300 feet.
28) Pump a 100’ balanced corrosion resistant cement plug from 100 feet to surface.
29) Cut and cap casing 3 to 4 feet below ground level.

A certified plugging report will be submitted to the UIC Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure. Also note that a complete well plugging record (Form W-3), pursuant to 16 TAC §5.203, will be filed within 30 days after plugging to the appropriate TRRC District Office.

9.9.2.3 Plug Information

The operator will report cement densities and retain duplicate samples of the cement used for each plug. For all cement plugs, 0% excess will be used. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 9-7 and **Figure 9-10** present details for each plug and the proposed plugging schematic, respectively.

Table 9-7: Midland IZM #2 Well Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7	Plug #8	Plug #9	Plug #10	Plug #11	Plug #12
Diameter of boring in which plug will be Placed (inches)	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826	3.826
Sacks of cement to be used (sks)	121	NA	23	15	15	22	15	15	NA	4	8	8
Slurry volume to be Pumped (cu.ft.)	126.2	NA	24	16	16	23.3	16	16	NA	4	8	8
Slurry Weight (lb/gal)	16.4	NA	16.4	16.4	16.4	16.4	16.4	16.4	NA	16.4	16.4	16.4
Length of cement	1,580	NA	300	200	200	292	200	200	NA	50	100	100
Calculated top of Plug (ft)	12,205	12,160	11,860	11,351	10,691	8,900	7,500	4,008	1,350	1,250	300	0
Bottom of plug (ft)	13,785	NA	12,160	11,551	10,891	9,192	7,700	4,208	NA	1,300	400	100
Type of cement or other material	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Circulation	Workstring	Circulation	Circulation	Circulation	Circulation	Circulation	Circulation	Workstring	Circulation	Circulation	Circulation

MILESTONE CARBON

Well Name:	Midland IZM #2
API:	
UIC:	
State:	TX
County:	Upton
Field:	Midland
Lease:	Dusek
Elevation:	2,796'
Depth (TVD):	13,785'
Texas Central NAD 83	
Lattitude:	31.608086°
Longitude:	-101.983038°

Casing Program

		OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1	Surface:	13 3/8	54.5	J-55	BTC	12.615	17 1/2	0	1,300	0
2	Intermediate:	9 5/8	53.5	L80	VAM 21	8.583	12 1/4	0	9,000	0
3	Production:	4 1/2	15.1	L80	SLIJ-II	3.826	7 7/8	0	11,600	0
4				25CRW	SFJ			11,600	13,785	11,600

Figure 9-10: Representative Plugging Schematic In-Zone Monitoring Well

9.9.3 Plugging the USDW Well(s)

Notification, regulatory and plugging procedures will include:

9.9.3.1 Pre-Plugging Activities

1) In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.
2) External mechanical integrity will be demonstrated with temperature, noise or oxygen activation logging.
3) Casing inspection and cement bond logs will be performed prior to plugging. Log evaluation will determine if revision to the plugging procedure is necessary.

9.9.3.2 Plugging Activities

1) Make up and run corrosion resistant bridge plug and set with workstring above perforations at 1,000 feet.
    a. Tag and pressure test bridge plug.
2) Pump a 20' corrosion resistant cement plug above bridge plug from 1,000 to 980 feet.
3) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 980 feet.
4) Position workstring at 400 feet and pump a 100-ft balanced corrosion resistant cement plug from 400 feet to 300 teet.
5) Wait on cement, tag and pressure test the cement plug.
    a. If the plug is tagged deeper than planned, an additional corrosion resistant cement plug will be set up to 300 feet.
6) Position workstring at 100 feet and pump a 100-ft balanced corrosion resistant cement plug from 100 feet to surface.
7) Cut and cap casing 3 to 4 ft below ground level.

A certified plugging report will be submitted to the UIC Director within 60 days after plugging pursuant to 40 CFR §146.91(e). The plugging report will be retained for 10 years following site closure. Also note that a complete well plugging record (Form W-3), pursuant to 16 TAC §5.203, will be filed within 30 days after plugging to the appropriate TRRC District Office.

9.9.3.3 Plug Information

The operator will report cement densities and retain duplicate samples of the cement used for each plug. For all cement plugs, 20% excess will be used to ensure isolation is achieved. All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1k feet of depth from the ground surface to the bottom of the plug. Milestone is currently evaluating CO_2 resistant cement from the industry's leading suppliers, Halliburton and SLB. ThermaLock is an option from Halliburton. EverCrete and Ecoshield are two (2) options from SLB. All the cement solutions have been thoroughly tested and are designed to maintain reliable corrosion resistant properties throughout the life of an injection or monitoring well exposed to CO_2. The products listed above are all rated for the temperature and pressure ranges of the injection and monitoring wells. They will provide long lasting zonal isolation.

ThermaLock is a non-Portland based cement that is a specially formulated calcium aluminate phosphate system which gives it resistant properties to CO_2 corrosion.

Evercrete has long been the reliable workhorse for CO_2 injection wells. Its low permeability allows it to withstand corrosive effects of supercritical CO_2 and has self-healing properties if a fracture is formed. Ecoshield is a geopolymer cement free system that provides an alternative to Portland cement while delivering comparable performance. EcoShield system matches the rheology, thickening time, and compressive strength properties of Portland cement-based systems. The technology fits within standard oilfield cementing workflows without major changes to the design process, onsite execution, or post-job evaluation.

This is an evolving science, and Milestone will continue evaluating the most suitable corrosion resistant cement product for the proposed well plugging. Cement and cement additives will be compatible with the injectate stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.

Table 9-8 and **Figure 9-11** present details for each plug and the proposed plugging schematic, respectively.

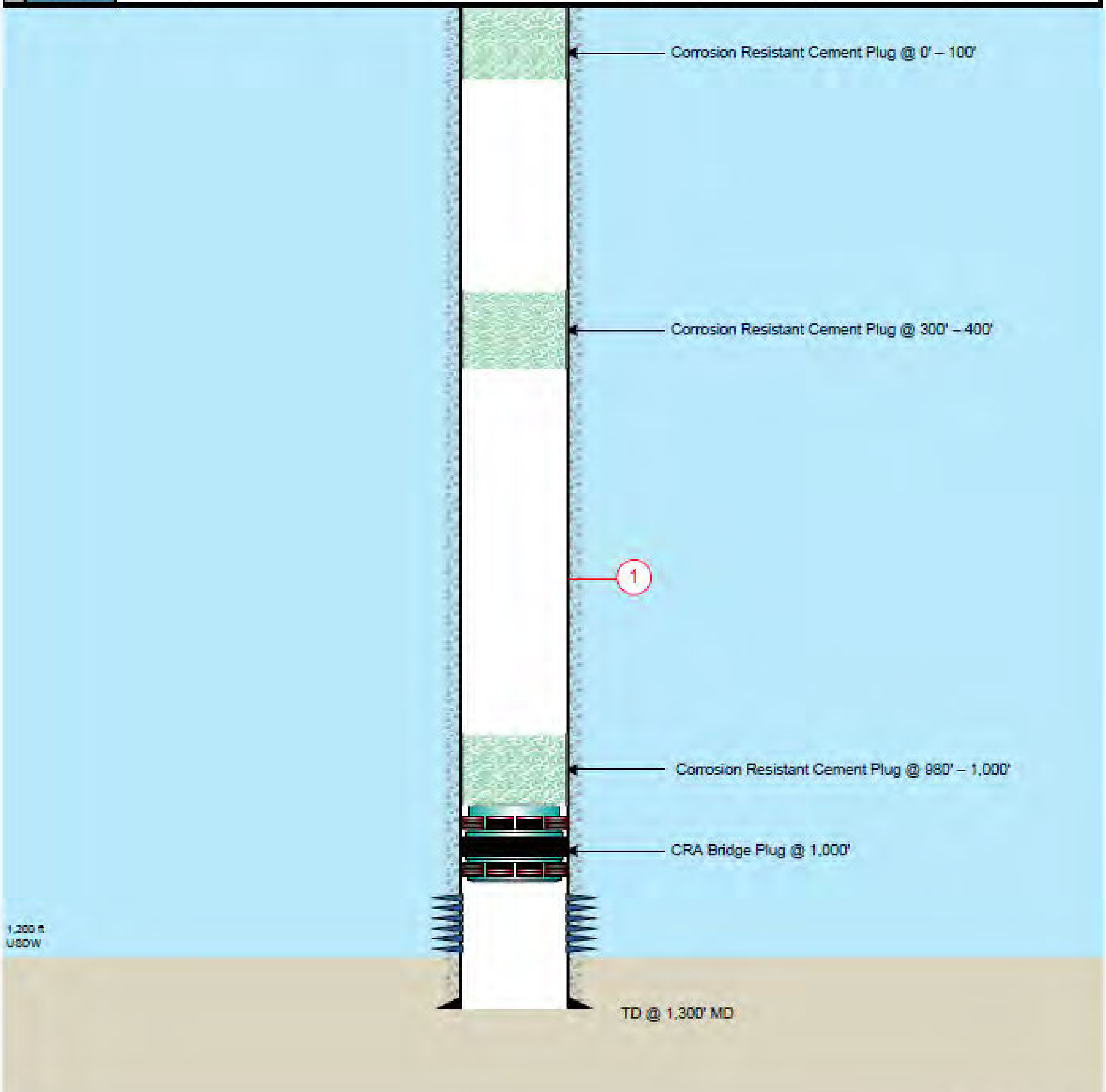
Table 9-8: Midland USDW #2 Proposed Plugging Program Detail

Test Description	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be Placed (inches)	5.012	5.012	5.012	5.012
Sacks of cement to be used (sks)	NA	3	13	13
Slurry volume to be Pumped (cu.ft.)	NA	2.8	13.8	13.8
Slurry Weight (lb/gal)	NA	16.4	16.4	16.4
Length of cement	NA	20	100	100
Calculated top of Plug (ft)	1,000	980	300	Surface
Bottom of plug (ft)	NA	1,000	400	100
Type of cement or other material	CRA Bridge Plug	Corrosion Resistant	Corrosion Resistant	Corrosion Resistant
Method of emplacement	Workstring	Circulation	Circulation	Circulation

Well Name:	Midland USDW #2
County:	Upton
State:	TX
Depth (TVD):	1,300

Casing Program

	OD (in)	Weight (lb/ft)	Grade	Connection	ID (in)	Drift (in)	Hole Size (in)	Casing Top (ft)	TVD (ft)	Cement Top (ft)
1 Surface:	5 1/2	14	J-55	BTC	5.012	4.887	7 7/8	0	1,300	0



Printed: 3/27/25

Figure 9-11: Representative Plugging schematic – USDW Monitoring Well

9.9.4 Plugging the Near Surface Seismometer-Water (NSSW) Wells

If the near surface seismometer water wells (NSSW) wells are still serviceable and the seismicity equipment still useful, the wells will not be plugged at the completion of the project. Instead, they will be assigned to the landowner or TexNet for their private use.

If the landowner or TexNet declines to take ownership of the NSSW wells. The wells will be plugged according to the following procedure found in TCEQ Regulatory Guidance, Texas Groundwater Protection Committee, RG-347, Rev. April 2021, "Landowner's Guide to Plugging and Abandoned Wells." **Figure 9-12** illustrates the details of the proposed plugging.

9.9.4.1 NSSW Plugging Activities

1) Milestone will hire a water well drilling company licensed and bonded in the state of Texas
2) Water level will be measured to calculate proper mixtures of disinfection and plugging materials
3) Well will be disinfected with bleach to ensure microorganisms are not sealed in the aquifer
4) As much casing as possible will be removed from the wells
5) Using a tremie tube, the well will be pressure filled with a Bentonite grout and then capped with a cement cap at least two (2) feet thick and within four (4) feet of the ground surface. It will then be topped off with native soils
6) A report will be submitted to the TCEQ - Department of Licensing and Regulation.
7) TLDR Plugging report form WWD004N will be submitted to the TLDR
    a. Within the Plugging report form the licensed water well driller will certify the plugging of the well in section D. Milestone's licensed contractor will use an updated form if one is available at that time.

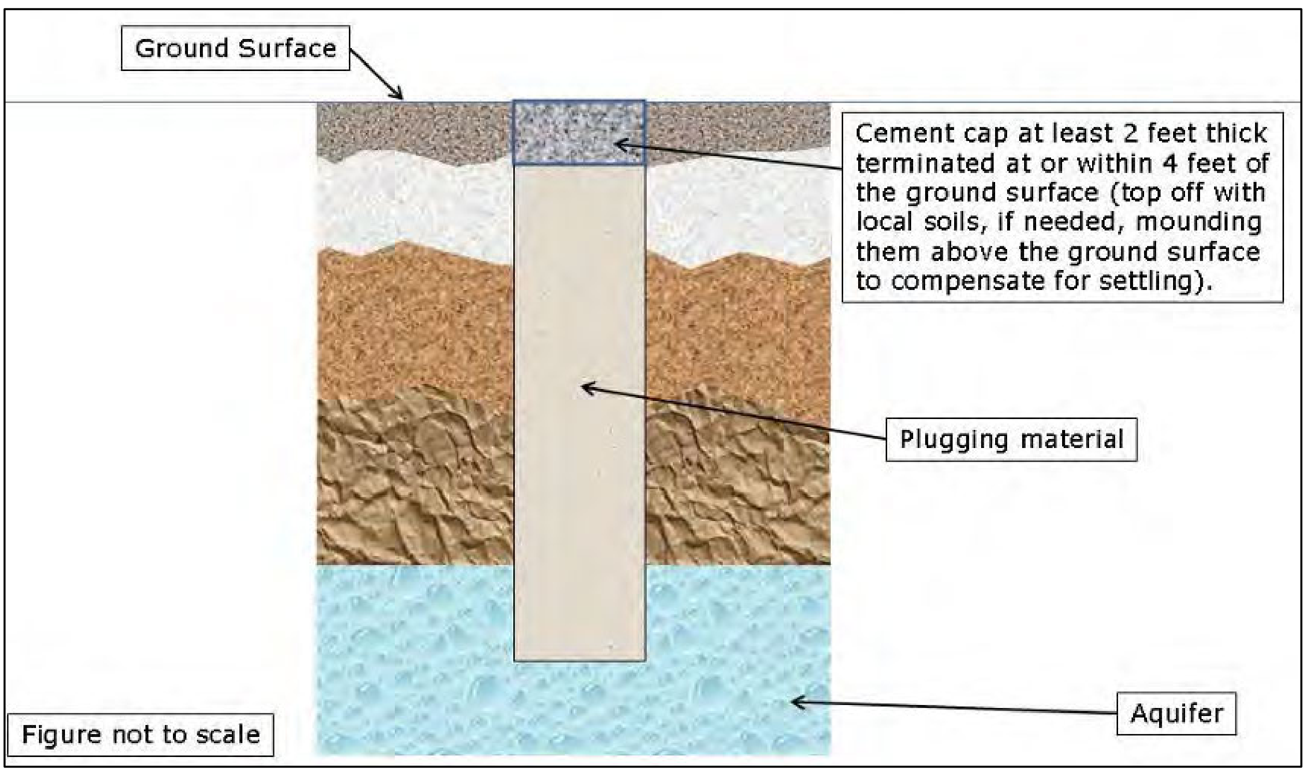


Figure 9-12: Approximate Plugging schematic – NSSW Monitoring Well (Source: TCEQ)

9.9.5 Planned Remedial/Site Restoration Activities [146.93 (a)]

To restore the site to its pre-injection condition following site closure, Milestone will be guided by the State rules for plug and abandonment of wells located on leased property under TCEQ Regulatory Guidance, Texas Groundwater Protection Committee, RG-347, Rev. April 2021, "Landowner's Guide to Plugging and Abandoned Wells."

The following steps will be taken:

1) The free liquid fraction of the plugging fluid waste, which may consist of produced water and/or crude oil, shall be removed from the pit and disposed of in accordance with state and federal regulations (e.g., injection or in above ground tanks or containers pending disposal) prior to restoration. The remaining plugging fluid wastes shall be disposed of by injection in Milestone Environmental Services (MES) owned/operated slurry site or if solids, MES owned/operated landfill.
2) All plugging pits shall be filled and leveled in a manner that allows the site to be returned to original use with no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support farm machinery.
3) All drilling and production equipment, machinery, and equipment debris shall be removed from the site.
4) Casing shall be cut off at least four (4) feet below the surface of the ground, and a steel plate welded on the casing or a mushroomed cap of cement approximately one (1) foot in thickness shall be placed over the casing so that the top of the cap is at least three (3) feet below ground level.
5) Any drilling rat holes shall be filled with cement to no lower than four (4) feet, and no higher than three (3) feet, below ground level.
6) The well site and all excavations, holes and pits shall be filled, and the surface leveled.

9.9.6 Site Closure Report [146.93(a)(2)(iii)]

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the Midland IZM #2 and USDW #2 monitoring wells (and the injection well if it has not previously been plugged),
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to State and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

Milestone will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure. Additionally, the operator will maintain the records collected during the PISC period for a period of 10 years after which these records will be delivered to the UIC Program Director.

9.10 Quality Assurance and Surveillance Plan (QASP)

The primary goal of the testing and monitoring plan (**Section 6**) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with applicable Texas statewide rules regarding Testing and Monitoring Requirements, this quality assurance and surveillance plan (QASP) – **Section 13 Appendix C** was developed and is provided as part of the testing and monitoring plan.

Appendix C reflects Milestone's Quality Assurance Surveillance Plan (QASP) for testing and monitoring activities is pursuant to the requirements listed in 40 CFR §146.90(k), 146.93(c)(2)(i) and §146.93(c)(2)(vii) addressed in detail in Milestone permit application **Sections 6** and **Section 9**. This performance-based plan sets forth the procedures and guidelines the Environmental Protection Agency (EPA) will use in evaluating the technical performance of Milestone. The operating plans for the proposed Well will include a robust testing and monitoring program. Milestone will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91.

UIC CLASS VI GEOLOGIC STORAGE OF CO_2 PERMIT APPLICATION

Midland CCS Hub

South Midland Facility

Upton County, Texas

Attachment J: Financial Assurance Demonstration Plan (FADP)

[40 CFR §146.82 (a), §146.85]

Prepared for:

Railroad Commission of Texas

1701 N. Congress Ave., Austin, TX 78701

Prepared and submitted by:

Milestone Carbon Midland CCS Hub, LLC

840 Gessner Rd, Suite 600

Houston, Texas 77024

Petrotek Corporation

5935 South Zang St, Suite 200

Littleton, Colorado 80127

Updated 4 February 2026

Table of Contents

List of Tables

List of Figures

11.0 FINANCIAL ASSURANCE DEMONSTRATION PLAN (FADP) [CFR 146.82(a)(14) and 146.85; 16 Texas Admin Code § 5.205]

Milestone is providing financial responsibility (Financial Assurance or FA) pursuant to 40 CFR 146.85 and 16 Texas Admin Code § 5.205 and proposes the use of a Surety Bond to cover the costs of: corrective action, emergency and remedial response, injection well plugging, post-injection site care, routine monitoring/reporting activities, and site closure. In compliance with 40 CFR 146.85(a)(4) and Texas Statewide Rule 5.205 (c)(2)(D)(iii), these instruments will provide that they may not be cancelled or terminated except due to failure to make payment and, in such event, the cancellation or termination may not be final until 120 days after receipt of cancellation or termination notice mailed to Milestone and the permitting authority. All cost estimates were generated by an independent third party, Petrotek, of Littleton, Colorado.

11.1 Independent Third-Party Cost Estimation [CFR 146.85 (C) (1); 16 Texas Admin Code § 5.205 (C)(2)(C)]

Milestone contracted an independent third-party professional engineering firm to perform all cost estimates, Petrotek, of Littleton, Colorado. Petrotek employs professional engineers licensed in the state of Texas

The cost estimate was performed for each phase separately and was based on the costs required for the regulatory agency to hire a third party to perform the required activities. Petrotek is not within the corporate structure of Milestone.

Petrotek, on Milestone's behalf, provides a tabular detailed written estimate, in current dollars, of the cost necessary to perform corrective action on wells in the area of review, plugging of injection wells, post-injection monitoring and closure of the facility, and emergency and remedial response that shows all assumptions and calculations used to develop the estimate.

Petrotek employs qualified professional engineers licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, and has prepared or supervised the preparation of a written estimate under seal of the highest likely amount necessary to close the geologic storage facility. Included in the FA appendix is a separate letter that seals the estimate as required under 16 Texas Admin Code § 5.205 (C)(2)(C)(ii).

11.2 Approach to Meeting Financial Assurance Requirements

Milestone will secure a surety bond to meet FA requirements for any corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response activities.

Milestone will secure a surety bond necessary to perform corrective action, emergency and remedial response/remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of injection or monitoring wells at any time during the permit term in accordance with all applicable EPA regulations, Texas state laws, Railroad Commission rules and orders, and the permit.

If there are any remaining components required for financial assurance demonstration, these will also be secured by a Surety Bond and/or by Letter of Credit. A standby trust will be established for the surety company to make payments.

11.2.1 Financial Mechanism: Surety Bond

To satisfy its financial responsibility obligations for corrective action, injection well plugging, post injection site care, site closure, emergency and remedial response activities and, other than items covered by Surety Bond as described herein, Milestone will secure either a payment or performance bond using the forms – **Section 13 Appendix J.** The bond will be issued by a surety company that meets the requirements of 40 CFR 146.85(a)(6)(ii). It is understood that should Milestone fail to meet the requirements specified in the bond; the surety company is liable for the costs. Milestone will also establish a standby trust into which the surety company will make payments if Milestone fails to comply with its financial responsibilities. The trust agreement form (**Section 13 Appendix J**) will be used to establish the standby trust. Money deposited into the trust fund established by standby trust can then be used to pay a third party to perform corrective action, closure/post-closure activities and emergency and remedial response.

Milestone may use one of the following two types of bonds to meet the financial assurance requirements:

1. **Payment Bond** - guarantees that if the owner/operator fails to pay for corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response, the surety company will pay the costs into the fund established by the standby trust.
2. **Performance Bond** - guarantees that if the owner/operator fails to perform all the required corrective action, injection well plugging, post injection site care and site closure, and/or emergency and remedial response activities, the surety company will either perform the required activities or pay sufficient funds into the fund established by standby trust.

The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection will be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection will provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

In case it is unclear, the bond amount will be the composite p90 of the total FA distribution.

11.3 Corrective Action Plan

The detailed AoR and Correction Action Plan are located in **Section 2** of this permit application. Milestone has determined that there are zero (0) wells in the proposed AoR for which corrective action is required prior to, or during, the course of this project operation or post-closure period. However, in the event wells within the AoR are determined to require correction action, Milestone will demonstrate its financial responsibility for such actions by including the projected costs in the surety bond to be provided as set forth in **Section 11.2.1**. The AoR will be re-evaluated every five (5) years to determine if any new penetrations have occurred and whether such penetrations require corrective action.

Even though there are zero (0) wells within the AoR that penetrate the Injection Interval or Top Seal and require corrective action, there are ongoing monitoring activities that require cost estimation. Milestone has assigned a cost to monitoring future permits and possibly plugging and testing heretofore undiscovered wells. Therefore, Corrective Action costs contemplate the low probability future event that a deficient well is permitted by the RRC to drill into the AoR or a historical well is discovered to penetrate the Top Seal or Injection Interval in the future.

11.4 Injection Well-Plugging Program

Plug and abandonment (P&A) of the Midland CCS #2 Well is included within the project operating cost and is covered within this Financial Assurance Demonstration Plan and proposed surety bond. The specifics of the plugging program can be found in **Section 8 – Injection Well Plugging** of the permit application. Costs were estimated using work scopes provided by third-party industry experts and comparable third-party costs for performance of services and procurement of associated material and equipment. The estimate covers the aggregated P&A cost of one (1) injection well, including rig mobilization, rig and equipment rentals, cementing, logging, haulage, and P&A reporting. To ensure a conservative estimate, no cost deductions were made to salvage the value of materials. The projected cost of Injection Well Plugging will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.5 Post-injection Site Care (PISC)

PISC and facility closure estimates include site monitoring and periodic reassessment of the AoR, facilities maintenance and power costs, overhead and support costs. Details of the activities and actions contained in the PISC can be found in permit **Section 9 – Post Injection Site Care**. The largest element of the PISC cost estimate relates to geophysical surveys and wells' subsurface data capture carried out at periodic intervals and which will cover the USDW and IZM monitoring wells, the five (5) NSSW monitoring wells, and an AoR area of up to 8.4 mi^2. Costs for PISC were developed using historical data, SME estimates, and Vendor estimates for specific materials and equipment. The estimates cover mobilization, detector arrays' installation, surveying, field-sampling, lab analyses, data processing, land agreements, and data interpretation-reporting. The post injection regulatory fee of $50K per year is also included in this amount. The projected cost of PISC will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.6 Facility Closure

Facility closure includes casing evaluation, mechanical integrity verification, P&A activities and site reclamation costs for all sampling and geophysical monitoring wells including the Midland USDW #2, Midland IZM #2, and Midland NSSW #1-5 wells. It also includes fieldwide removal of surface equipment and remediation of inter-well sites soil and/or aquifer contamination. Site Closure reporting costs are included in the Site Closure total estimate. The projected cost of Site Closure will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.7 Emergency & Remedial Plan

The Emergency and Remedial Response Plan (ERRP) and associated detailed assessment can be found in **Section 10 – Emergency and Remedial Response Plan** of this permit application.

Milestone conservatively estimated costs associated with emergency and remedial response related to each of the emergency events described in **Section 10** (ERRP) of this application, including well integrity failure or loss of mechanical integrity, injection well monitoring equipment failure, a spill, CO_2 or subsurface fluid migration out of the injection zone, damage due to a natural disaster, and damage due to induced seismicity. Most of these emergencies fall under site shut down, well control or other emergency remedial implementations, mechanical integrity event. The activities related to these ERRP events, as provided by Milestone, are presented in **Section 10 - Table 10-1** to **Table 10-7**. Estimated costs associated with ERRP events are shown in **Table 11-6**.

The cost estimates for well integrity failure or loss of mechanical integrity, CO_2 or subsurface fluid migration out of the injection zone, damage due to a natural disaster, and damage due to induced seismicity are conservatively based on a Monte Carlo analysis of the costs associated with a hypothetical worst-case scenario wherein a significant volume of briny water or CO_2 escapes to the surface. The scenario contemplates a reactive response approach – for example – mobilization of response personnel and equipment upon discovery of such an event. This approach is considered appropriate because of the remoteness of the residual risk. Specific post-occurrence action is not determinable until occurrence; thus, actual response to such an event would be based on its severity level. Costs associated with this scenario are intended to account for the outer-limit estimate to satisfy event response. The cost estimate is based on the optimal operating conditions (10 years' operation) requiring outer-limit response and remediation costs.

The cost estimates also account for a scenario in which CO_2 or subsurface fluids migrate and potentially endanger an underground source of drinking water (USDW). The risk of endangerment to USDWs is considered remote and unlikely given the large number of impermeable layers between the injection zone and USDW. However, as part of the reactive response scenario contemplated in the ERRP cost estimate, Milestone assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water.

Milestone will utilize its Spill Control and Prevention Plan in combination with the response strategy to minimize this portion of environmental repair. This subsurface migration and USDW endangerment have primary costs related to groundwater delineation and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken. The projected cost of emergency and remedial response will be included in the surety bond to be provided as set forth in **Section 11.2.1**.

11.8 Methodology – Monte Carlo Simulation

As a way of addressing and managing cost-estimation input-data uncertainties, FA analysis employed Monte Carlo simulation for stochastic modeling. From the EPA we note: "*It is the policy of the U.S. Environmental Protection Agency that such probabilistic analysis techniques as Monte Carlo analysis, given adequate supporting data and credible assumptions, can be viable statistical tools for analyzing variability and uncertainty in risk assessments*." (Fred Hansen, EPA, 1997, p. 1.)

The specific simulator used was RiskAMP™, a full-featured Monte Carlo simulation engine add-in for Microsoft Excel written by, and sourced-through, Structured Data LLC. The RiskAMP add-in includes more than 40 random distribution functions allowing for good, practical, contextual application specific to intuited or estimated project and/or FA activities operational constraints.

Basic to FA, is knowing the cost of effectively meeting the compliance mandates listed and described in Project Financial Assurance section above. The purpose and scope of this FA assessment (Fred Hansen, EPA, 1997, p. 2) is a composite and accurate estimate of the costs of that compliance. Such estimation is challenged on three fronts: data uncertainties, sourcing, and assumptions.

11.8.1 Uncertainties

For FA estimation, the first uncertainty is the lack - that comes with a relatively new industry - of corresponding historical cost data. The geologic sequestration of CO_2 via the method of deep subsurface injection remains a relatively new undertaking. This applies most directly to data sets worthy of parametrization in the service of cost estimation. Data useful for infrastructure and operational costs evaluation continues to be scarce, and thereby subject to application only through indirect comparison and analogy – in particular, through the use of data reflecting oil and gas (O&G) fields' subsurface infrastructure development and operations costs. Such O&G costs reflect global markets, are affected politically, and have a history of price/cost volatility. Accordingly, the nature of volatile cost-data comparisons brings compound uncertainties; and inevitably, extended ranges.

The second uncertainty is the evolving cost of applied technologies, materials, and their associated operational changes to be employed for compliant management of CO_2 geologic sequestration. As the subsurface carbon sequestration industry grows and matures, changes to regulatory design and operational standards are probable, and are equally likely to materially impact the cost of doing business – even post-injection.

The third is the uncertainty with shifting EPA, TRRC, or TCEQ standards regarding FA, FA costs estimation, associated risks assessment, and practical assessment of risk-underwriting scale and scope.

11.8.2 Data Sources

This FA analysis aligned with EPA's UIC Program Class VI Financial Responsibility Guidance (EPA, 2011) as the basis to define the activities required to be included in the cost estimate. Supported by that guidance, Milestone Carbon's FA-relevant Permit Application sections (EPA phases) were reviewed for operational and technical approach, for CO_2 injection model output, and post-injection FA activities' durations and periodicities.

Additionally, for FA required activities, both estimated costs and their stochastic treatments were guided by a variety of Agencies', National Laboratories', Universities', and Industries' data and expertise. Sources included:

- Historic price data from other Petrotek managed UIC projects and FA analyses;
- Cost quotations from third-party service providers;
- Academic investigation and assessment of distribution functions application;
- PNL's Assessment of the Geomechanical Risks Associated with CO2 Injection at the FutureGen 2.0 Site (PNL, 2019);
- EPA's Geologic CO_2 Sequestration Technology and Cost Analysis (EPA, 2008);
- DOE's Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement (NETL, 2007);
- NETL's Overview of Potential Failure Modes and Effects Associated with CO2 Injection and Storage Operations in Saline Formations (DOE/NETL, 2020); and
- Petrotek professional engineering, project management, and estimation expertise.

11.8.3 Data Assumptions

Almost by definition, estimation of FA cost looks far into future technologies and operational cost relationships. Realities of carbon sequestration industry price escalation and general macroeconomic inflation are important factors. However, aligned with EPA Class VI Permit Application submission requirements (EPA, 2011, p7) for initial FA analysis, "current dollars" (April 2025) are employed.

11.8.4 Monte Carlo Simulation

Monte Carlo simulation has been used for estimating FA costs in the current evaluation. While this overview does not aim to be a comprehensive guide on the technique, a brief explanation of Monte Carlo simulation will help contextualize its application for this Milestone Carbon FA evaluation, which focuses on future events.

Monte Carlo simulation is a computational method that uses random sampling to model and analyze uncertain systems or processes. In cost forecasting, this technique involves running numerous iterations with varying input values and assumptions to generate a range of possible cost estimates. By examining different combinations of input variables, such as FA cost drivers, (e.g. probability of events, ranges of costs), Monte Carlo simulation captures the inherent uncertainty in forecasting.

The core idea behind Monte Carlo simulation is that any uncertain variable, such as the cost of an unanticipated event, can be represented by a probability distribution. This distribution describes the range of possible values and their likelihood. For example, a probabilistic cost estimate of an FA operational activity might be appropriately modeled using a parameterized distribution reflecting Gaussian (normal), Weibull, beta-PERT, Gamma, etc. distributions. According to the particular activity modeled, each distribution would be chosen and parameterized specific to the nature of the activity's estimated scale, scope, periodicity, duration, and probability. By assigning crafted probability distributions to specifically uncertain variables in the FA cost analysis, we create a mathematical model of the total FA cost estimate.

The process involves using a random number generator to sample values from each distribution and calculate a total event cost. Repeating this process many times produces a large set of simulated event costs, which form a frequency distribution. This distribution reveals the most likely FA total cost, percentiles of cost, as well as the minimum and maximum possible costs. It also shows the probability of achieving a specific cost target or staying within a certain range. This information helps assess the likelihood or probability of the FA cost based on the model.

Monte Carlo simulation is particularly useful for addressing and quantifying uncertainties in complex, future, and non-linear systems. In the context of FA, it combines multiple cost and probability estimates - first individually and then aggregated through Monte Carlo analysis - to provide a range of possible FA costs and associated probabilities. Compared to other forecasting methods, such as deterministic or single-point estimates, Monte Carlo simulation offers several advantages. It:

- Captures the complexity and interdependence of multiple variables and factors that affect FA cost, such as resource availability, quality issues, and external risks;
- Provides a realistic and comprehensive view of the uncertainty and variability of FA cost, and quantifies the level of confidence and accuracy of the estimate;
- Identifies the key drivers and contributors of FA cost and highlights potential areas of high risk and/or opportunity;
- Supports decision making and risk management by providing quantitative treatments and metrics. These include FA total and FA phases' costs range, mean, median, mode, standard deviation, confidence intervals, percentile distributions, cumulative distributions, probability density distributions, and expected values; and
- Facilitates communication and presentation of the results by using graphical and numerical tools, (e.g., Probabilities and Costs) graphics and tables.

As noted, the RiskAMP Monte Carlo simulation engine was employed for all FA costs estimation simulation work. For this analysis, **250,000 iterations per model run** were used to assess the total FA cost impact generated by a set of **74 specific FA-related activities**. Each Monte Carlo simulation when run delivered a set of statistical metrics used to evaluate, compare, and contrast costs across the scale and range of Class VI operational activities addressed through FA estimation and assessment.

For FA costing and management, Milestone has elected to use model Monte Carlo distributions' "most probable cost" or Statistical Mode to represent FA costs for each major FA Phase (e.g., Injection Well Plugging, ERRP, etc.) as well for the Total Project FA cost. For the current Total Project model output with 250,000 iterations, the Mode of the FA Total Project equates to approximately a P63 value.

The mode is considered the "most probable value" from a distribution, because it occurs most often; in the same way that rolling a sum of 7 is the most probable value when rolling 2 six-sided dice and all other values have less combinations and are less likely. Said another way, the mode occurs at the peak of the probability distribution histogram, and it is the value or amount around which outcomes are most densely packed. 16 Texas Administrative Code § 5.205 (C)(2)(C)(ii) requires applicants to provide the *highest likely amount necessary* to close the geologic storage facility. Milestone interprets this phrase to be the statistical mode because it is the *highest likely* or *highest probability* value in the simulation.

11.9 Cost Estimates

Tables in this section provide a detailed estimate, in 2025 (April) dollars, of the cost of performing corrective actions on wells in the AoR, plugging the injection well, post-injection site care, facility closure, and emergency and remedial response. **Table 11-1** is a summary of the cost estimates underlying the FADP document, identifying proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of Milestone's intent and ability to fulfill its responsibilities. Petrotek Corporation of Littleton, Colorado, an independent third party, provided the estimates herein.

Cost estimates assume that these costs would be incurred if a third party were contracted to perform these activities. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the post-injection period, (e.g., the use of post-injection seismic surveys). Cost estimates are based on the Monte Carlo analysis previously described. These values are subject to change. Additionally, these values are driven by market forces such as changes in energy prices, inflation, contractor availability, materials costs etc. If the cost estimates change, Milestone will adjust the value of the financial instruments, and any adjustment will be submitted for approval as required under 40 CFR §146.85(a)(5).

The total estimated costs of each of these activities, as provided by Milestone, are presented in **Table 11-1**. Detailed estimates for major EPA Class VI phases are found in **Table 11-2** to **Table 11-7**. As noted above, even though there are zero (0) wells within the AoR, there is a non-zero chance that in the future Milestone could be required to perform corrective action. Therefore, a cost is provided for this low probability event.

Presented here **in Tables 11-1 through 11-7** are Monte Carlo model estimate statistics for each FA Activity, each FA Phase, as well as the FA for the Total Project. Except for *the Mean* (or *average*), *statistical* metrics (e.g., *median, mode, maximum*, etc.) do not sum to the same number/cost as the total distribution of the entire Phases' and Project Total reflected in Composite Statistical metrics. Statistical mathematics and Monte Carlo simulation algorithms do not work that way. In other words, the p90 of the parts does not sum to the p90 of the total.

Therefore, instead of the sum of the preceding column, shown at the bottom of each of FA Phases' **Tables 11-3 through 11-7** are composite statistical metrics taken directly from the *whole* of the Monte Carlo model run. **Table 11-2** reflects combined statistics of all FA phases as a composite.

Table 11-1: Aggregate Cost Estimates for Activities to be Covered by Financial Responsibility

Activity	Phases' P90 Cost Estimates ($USD)	Covered by Surety Bond
Corrective Action on Wells in AoR	**$329,625**	x
Plugging Injection Wells	**$1,895,586**	x
Post-Injection Site Care and Monitoring	**$7,443,774**	x
Site Closure and Plugging Monitoring Wells	**$8,787,996**	x
Emergency and Remedial Response (including Endangerment of USDWs)	**$8,488,440**	x
FA Composite Statistical p90 Estimate:	**$20,957,610**	**x**

11.9.1.1 *Composite Statistical Estimates for Total Project Table*

Table 11-2: Composite Statistical Estimates for Total Project FA Costs

Total Project FA Cost Statistics Types	Total Project FA Cost Estimate - USD
Mean	$17,991,169
Median	$17,496,690
Mode	$16,162,525
Standard Deviation	$2,490,764
Minimum	$13,244,831
P10	$15,520,527
P25	$16,346,083
P50	$17,496,685
P75	$19,028,498
P90	$20,957,610
Max	$52,147,417

11.9.2 *Tables of Monte Carlo Outputs by Category*

11.9.2.1 *Corrective Action Table*

Table 11-3: Cost Estimate for Corrective Action on Wells in AoR Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Ongoing AoR monitoring/modeling and Corrective Action on deficient well(s) in AoR.						
(Annual) Gather and organize operating data obtained during the CO2 injection phase.	$58,784	$59,271	$61,545	$4,486	$42,301	$67,133
(Annual) History match, update the model, and potentially-revise the AoR based on operational and monitoring data.	$73,439	$71,186	$62,835	$15,496	$47,412	$135,543
With AoR unexpected drift or growth, identify deficient well(s).						
Operational or post-injection phase well(s) database search.	$1,301	$875	$2,387	$1,366	$0	$19,097

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Operational or post-injection phase other well(s) surveys.	$58,176	$31,576	$191,011	$77,072	$0	$1,528,086
Operational or post-injection well(s) evaluation.	$15,106	$10,014	$7,120	$16,078	$0	$284,791
Well(s) evaluation report and submittal to EPA/State.	$14,846	$10,281	$27,562	$14,885	$0	$220,493
Address newly identified deficient wells.						
Research and purchase legacy, newly-identified deficient wells.	$194,094	$122,686	$616,372	$219,978	$0	$4,930,972
Purchased well(s)' cement remediation, plugging, and MIT.	$104,357	$62,477	$295,493	$125,947	$0	$2,363,940
Document and Report remediated well(s) plugging and MIT.	$7,733	$5,156	$16,589	$8,198	$0	$132,711
Composite Statistics: Ongoing AoR and Corrective Action on deficient well(s) in AoR	**$527,836**	**$462,467**	**$257,094**	**$265,831**	**$128,510**	**$5,271,900**

11.9.2.2 Plugging Injection Well Table

Table 11-4: Cost Estimates for Plugging the Injection Well Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Maximum
Flush injection wells with buffer fluid						
MIRU/RDMO	$50,238	$50,446	$50,594	$5,330	$34,455	$62,524
Casing Evaluation	$80,690	$80,192	$80,537	$10,662	$56,763	$112,701
Flushing fluid	$53,164	$52,303	$49,552	$5,590	$44,002	$75,714
Flush injection well	$13,741	$13,103	$11,543	$4,757	$5,503	$32,346
Perform MIT, assess BHP/reservoir pressure						
Assess BHP	$109,206	$108,294	$105,052	$12,276	$83,681	$149,440
External MIT (Tracer, temperature logs, specific other(s).	$143,450	$141,863	$135,235	$17,051	$110,031	$201,684
Plugging South Midland Facility CCS #2						
Engineering	$42,586	$42,562	$43,512	$6,146	$26,631	$58,785
MIRU/RDMO	$22,911	$22,810	$22,478	$3,103	$15,516	$31,897
Rig time and equipment rental	$504,549	$488,954	$429,756	$126,791	$275,088	$962,503
Miscellaneous services and labor costs	$82,019	$81,326	$79,777	$11,711	$56,737	$118,177
Cement cost	$399,925	$399,904	$395,560	$37,776	$301,720	$499,279
Plugging report	$39,400	$39,179	$37,706	$5,147	$27,555	$54,624
Composite Statistics: Injection Well Plugging Costs	**$1,541,880**	**$1,528,217**	**$1,478,480**	**$135,468**	**$1,185,142**	**$2,087,721**

11.9.2.3 Post Injection Site Care and Monitoring Table

Table 11-5: Cost Estimates for Post-Injection Site Care and Monitoring Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Acquire data: geochemistry, temperature, pressure, & CO2 saturation. (USDW, IZM, & CCS) #2 wells						
USDW #2 Fluid Sampling, Including U-tube installation cost/wireline cost. Includes captured-data periodic reporting costs.	$74,883	$74,028	$73,241	$12,440	$48,496	$114,483
USDW #2: pH and Electrical Conductivity (EC) detector array installation. Includes captured-data periodic reporting costs.	$42,269	$41,960	$39,920	$7,211	$25,779	$63,487
IZM #2 Fluid Sampling, U-tube installation, including estimated wireline cost. Includes captured-data periodic reporting costs.	$114,809	$113,720	$110,138	$13,593	$86,641	$158,941
NSSW #1-5 Fluid Sampling, U-tube, including wireline cost. Includes captured-data periodic reporting costs.	$46,090	$46,260	$47,059	$6,104	$28,647	$60,667
NSSW #1-5 pH and Electrical Conductivity (EC) monitoring detector array installation. Includes captured-data periodic reporting costs.	$38,520	$38,505	$37,939	$6,175	$22,602	$54,890
Midland CCS #2 & IZM #2 Pressure (DAS/DSS) & Temperature (DTS) monitoring (for IZM and USDW intervals). Includes captured-data periodic reporting costs.	$243,171	$240,030	$224,985	$29,111	$188,903	$349,268
Midland CCS #2 & IZM #2 Pulse Neutron Logging/RST (for IZM and USDW intervals). Includes captured-data periodic reporting costs.	$3,721,473	$3,601,324	$3,215,721	$657,828	$2,734,020	$6,587,625
Midland CCS #2 Fluid Sampling, Including U-tube installation cost/wireline cost. Includes captured-data periodic reporting costs.	$100,310	$98,469	$90,788	$9,529	$86,502	$143,646
Lab analyses and reporting (USDW, IZM, & CCS) #2 wells	$245,166	$233,118	$201,884	$72,824	$129,609	$542,608

Table 11-5 (continued): Cost Estimates for Post-Injection Site Care and Monitoring Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Post-Injection Direct and Indirect Plume Monitoring						
AoR Geophysical Surveys	$258,291	$255,378	$239,825	$46,169	$159,466	$406,725
Periodic AoR Computational Modeling and reporting costs.	$644,786	$637,222	$613,338	$72,805	$505,538	$897,539
Lab analyses and reporting (Midland CCS #2 well). Includes captured-data periodic reporting costs.	$241,667	$230,579	$186,033	$65,317	$139,899	$508,973
Other EPA required PISC Site management, monitoring, data analyses, data recording, & reporting.						
Potential other EPA required PISC Site management, monitoring, data analyses, data recording, data storage, and reporting. (Annual).	$255,420	$255,261	$249,642	$57,242	$107,788	$406,429
Composite Statistics: Post-Injection Site Care	**$6,026,856**	**$5,911,397**	**$5,805,841**	**$674,248**	**$4,607,704**	**$8,964,567**

11.9.2.4 Site Closure Table

Table 11-6: Cost Estimates for Site Closure Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Non-endangerment demonstration	$173,291	$169,824	$162,470	$30,789	$116,597	$283,409
Field-wide, remove surface equipment, remediate/restore surface, groundwater, and/or soil contamination.						
Field-wide, remove surface equipment.	$374,842	$362,733	$327,056	$77,664	$249,322	$693,515
Field-wide, remediate inter-well sites.	$495,428	$483,689	$457,572	$105,016	$300,358	$872,047
Field-wide, remediate groundwater and/or soil contamination.	$325,466	$149,024	$1,136,400	$488,530	$0	$9,091,202
Plug USDW #2 Monitoring Well						
Casing evaluation.	$20,834	$20,755	$20,720	$1,873	$16,528	$26,392
Engineering.	$15,060	$15,045	$14,934	$1,818	$10,416	$19,927
MIRU/RDMO.	$11,318	$10,844	$9,670	$2,877	$6,754	$23,418
Rig time & equipment rental.	$9,325	$9,201	$8,614	$1,110	$7,253	$13,304
Miscellaneous services & labor costs.	$27,191	$26,110	$22,200	$7,337	$15,003	$56,129
Cement cost.	$9,998	$9,995	$10,262	$1,890	$5,070	$14,959
Plugging report.	$14,992	$14,992	$15,276	$1,888	$10,077	$19,979
Plug IZM #2 Monitoring Well						
Casing evaluation.	$79,761	$79,245	$76,791	$10,903	$55,104	$112,936
Engineering.	$38,601	$38,575	$37,993	$6,136	$22,906	$54,669
MIRU/RDMO.	$22,406	$22,311	$21,913	$3,105	$15,034	$31,219
Rig time & equipment rental.	$505,180	$489,898	$431,646	$127,006	$275,305	$970,153
Miscellaneous services & labor costs.	$80,498	$79,750	$78,400	$11,692	$55,088	$117,252
Cement cost.	$400,148	$400,229	$404,864	$37,755	$300,889	$498,936
Plugging report.	$39,414	$39,192	$39,085	$5,143	$27,600	$54,625

Table 11-6 (continued): Cost Estimates for Site Closure Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Plug NSSW Monitoring Wells						
Well(s)' mechanical integrity testing.	$152,481	$150,765	$139,670	$28,082	$91,363	$240,002
Rig time & equipment rental	$132,224	$129,619	$117,883	$36,631	$54,956	$248,579
Miscellaneous services & labor costs.	$79,229	$79,302	$76,648	$16,096	$37,140	$120,315
Cement cost.	$600,009	$600,128	$607,615	$56,645	$452,398	$748,049
Plugging report.	$25,502	$24,803	$22,502	$4,570	$18,002	$43,714
Site Closure Report						
Site Closure Report: Site closure report includes subsurface injectate plumes' nature, composition, and volume, injection interval and period, all Injection, IZM and USDW wells closure status, post-injection monitoring records, and final surface remediation and restoration.	$64,352	$64,084	$61,603	$7,469	$46,994	$85,952
Texas State Fees related to Site Closure						
TRRC-specific Post Injection Care Fee of $50,000 per year for 50 years	$2,500,000	$2,500,000	$2,500,000	$0	$2,500,000	$2,500,000
Composite Statistics: Site Closure	**$6,197,550**	**$6,079,425**	**$6,854,279**	**$529,476**	**$5,188,780**	**$14,705,919**

11.9.2.5 Emergency and Remedial Response Table

Table 11-7: Cost Estimates for Emergency and Remedial Response Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Site shutdown						
Site assessment, Initial reporting	$1,392	$875	$630	$1,572	$0	$25,201
Well control or other emergency remedial implementations	$184,001	$95,359	$460,457	$252,214	$0	$6,139,420
Well(s) mechanical Integrity testing.	$1,116	$730	$2,516	$1,199	$0	$20,127
Scenarios : Post-injection USDW contamination						
USDW acidification due to CO2 migration	$252,708	$108,349	$318,174	$400,636	$0	$12,726,972
USDW toxic metal dissolution and mobilization	$649,492	$281,092	$1,575,045	$1,021,472	$0	$21,000,601
Displacement of USDW with brine due to CO2 injection	$1,150,674	$494,580	$2,562,262	$1,827,746	$0	$34,163,488
Critical scenarios : post-injection Failure						
Confinement interval failure (non-seismic)	$219,734	$102,801	$526,238	$326,704	$0	$7,016,510
Confinement interval or well integrity failure due to seismic event	$218,344	$102,738	$471,905	$320,948	$0	$6,292,061
Injection-monitoring equipment failure	$9,715	$5,362	$28,090	$12,538	$0	$224,721
Undefined surface spill	$315,115	$131,965	$383,560	$509,223	$0	$15,342,392
Undefined natural disaster	$315,212	$149,198	$692,573	$464,601	$0	$9,234,300
Chronic scenarios : post-injection Failure						
CO2 release through induced faults due to effects of injection increased-pressure	$68,624	$29,842	$182,607	$107,166	$0	$2,434,756
Well Integrity Failure: upward leakage through CO2 injection well	$140,202	$70,018	$329,684	$196,707	$0	$4,395,786

Table 11-7 (continued): Cost Estimates for Emergency and Remedial Response Phase

FA Activity	Mean	Median (P50)	Mode	Standard Deviation	Minimum	Max
Well Integrity Failure: upward leakage through undocumented, abandoned, or substandard legacy wells	$97,333	$49,224	$236,821	$135,938	$0	$3,157,617
Final and/or Corrective Action reporting to EPA						
Final Corrective Action reporting to EPA	$73,385	$67,608	$45,560	$33,536	$21,263	$215,637
Composite Statistics: Emergency & Remedial Response	**$3,697,048**	**$3,127,948**	**$6,620,638**	**$2,320,011**	**$316,050**	**$36,342,264**

11.9.3 Charts of Monte Carlo Output Distributions

Associated charts for each major category and the final project output displayed in **Figures 11-1** through **11-6** which contain the output distributions for each FA Phase. Several of the distributions contain long-tails indicating worst-case scenario(s) were contemplated but they are low probability event(s).

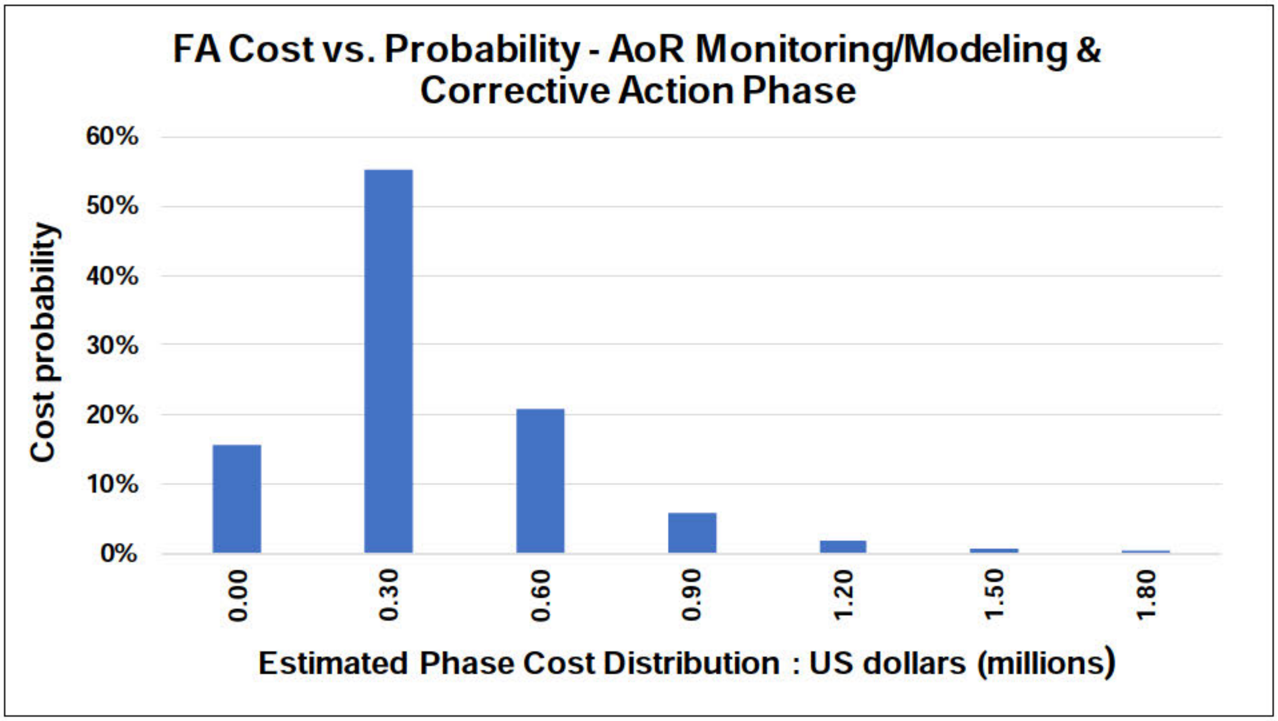


Figure 11-1: ***AoR and Corrective Action*** **Estimated Cost vs. Probability Distribution**

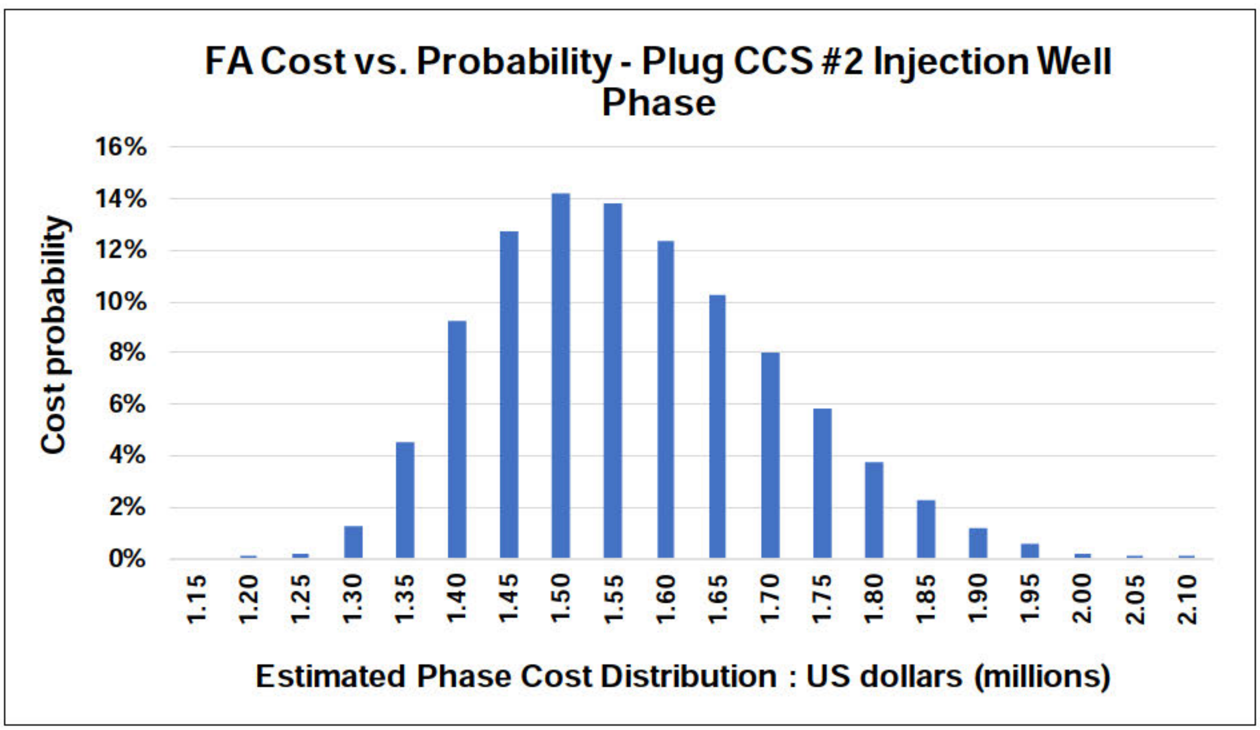


Figure 11-2: ***Plugging Injection Well*** **Estimated Cost vs. Probability Distribution**

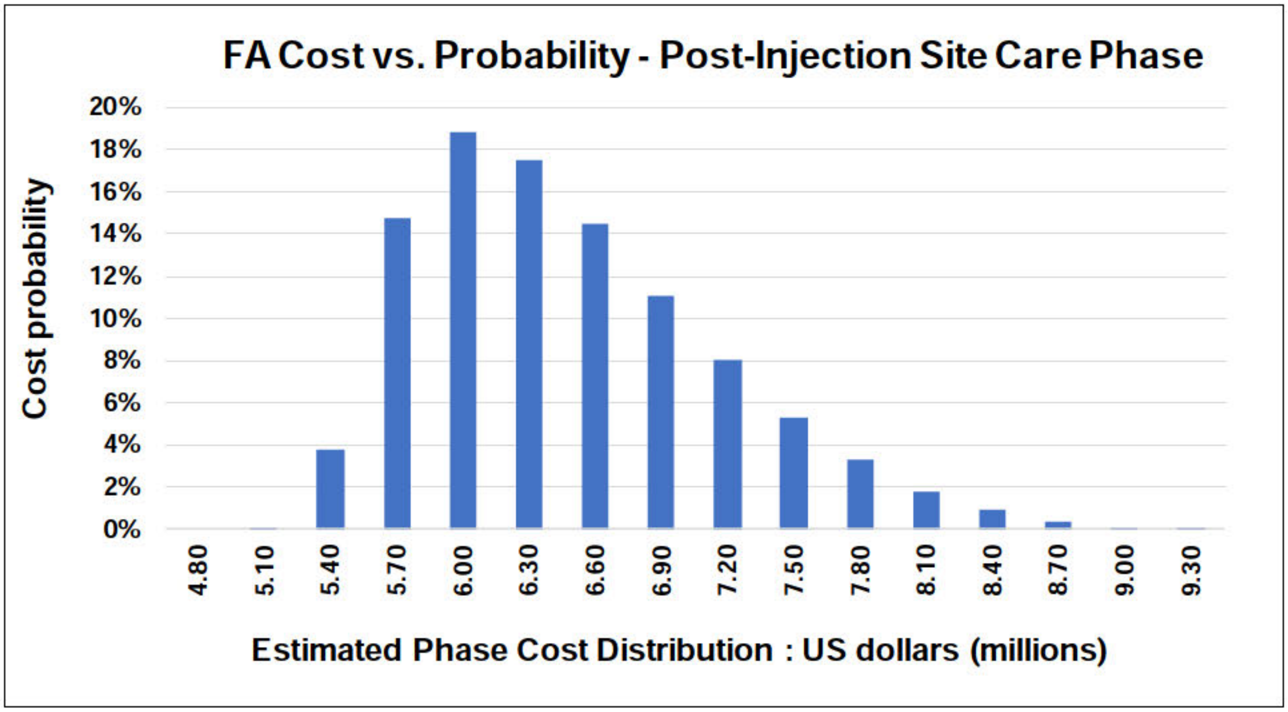


Figure 11-3: *Post Site Injection Care* Estimated Cost vs. Probability Distribution

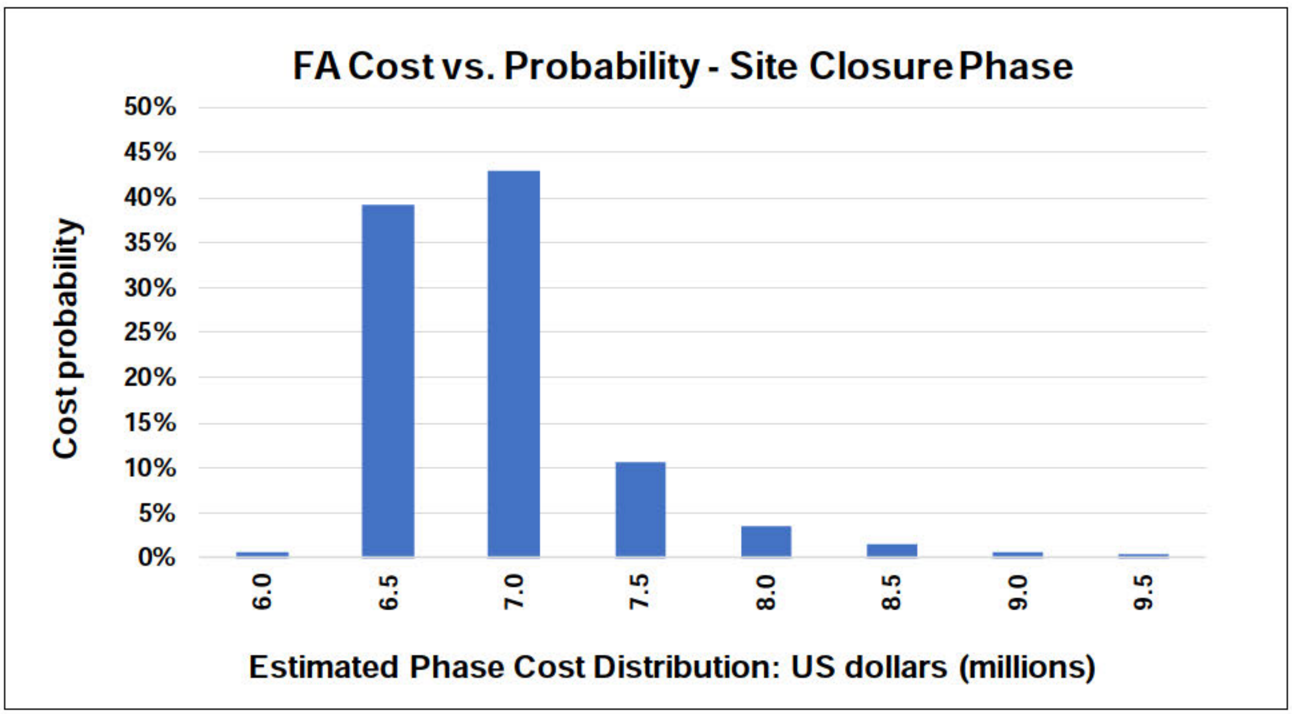


Figure 11-4: *Site Closure* Estimated Cost vs. Probability Distribution

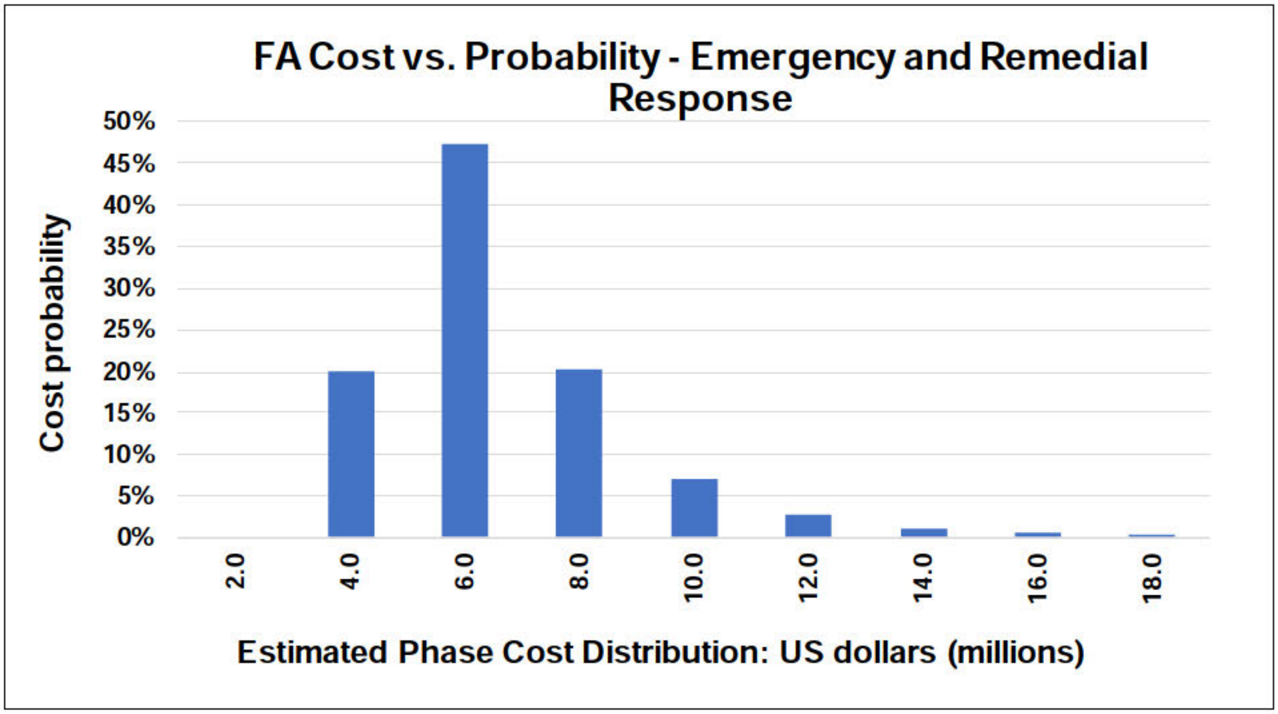


Figure 11-5: *Emergency and Remedial Response* Estimated Cost vs. Probability Distribution

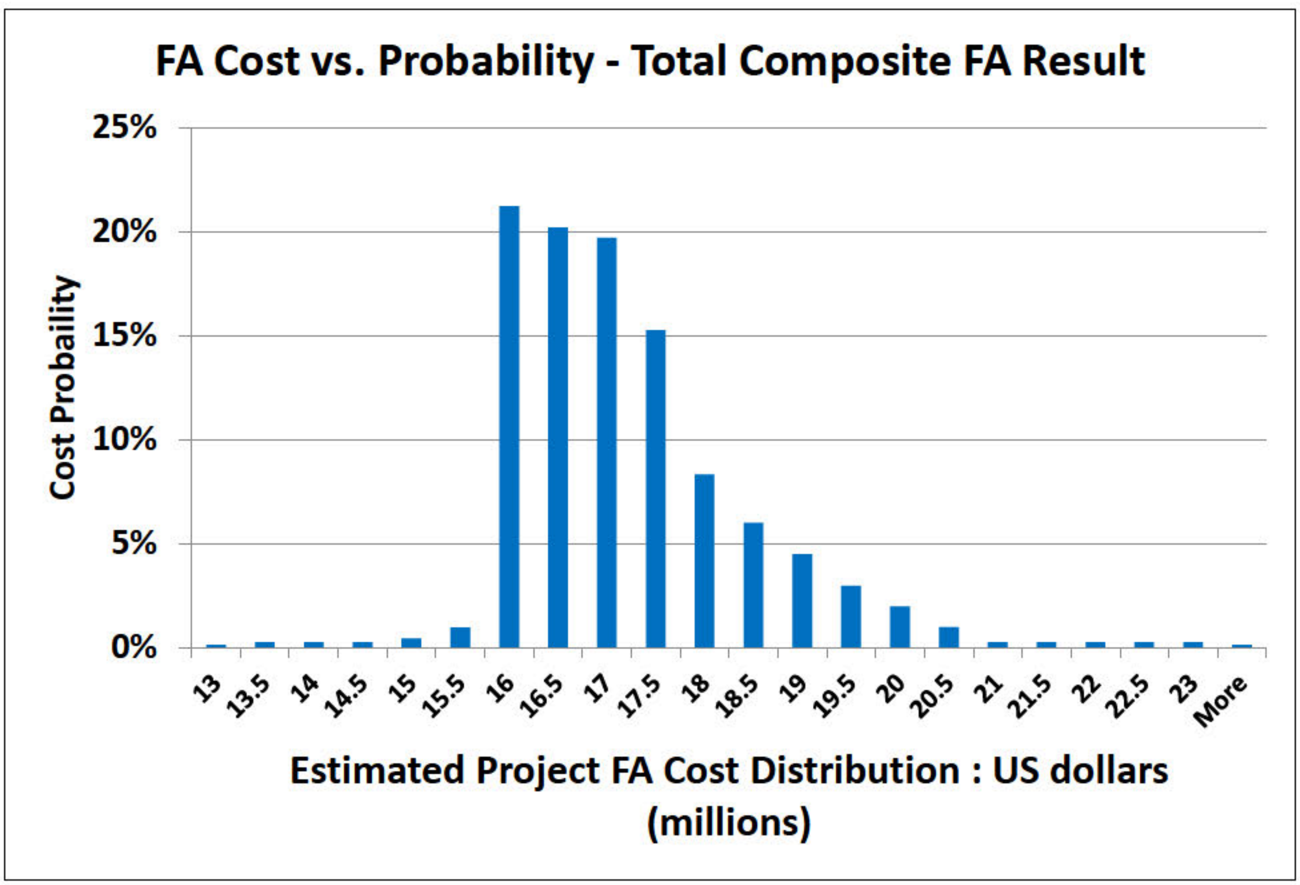


Figure 11-6: *Project Financial Assurance* Estimated Cost vs. Probability Distribution

11.10 Update and Reporting Schedule

On an annual basis, Milestone will provide a report to the UIC Director. If there are changes to the financial assurance estimate amount, Milestone will adjust the Financial Assurance amount within 60 days after changes are approved by the Director. Milestone will maintain financial instruments during the review period. If permit sections or cost estimates change regarding area of review and corrective action plan, injection well plugging plan, post-injection site care and or site closure plans, and or emergency response plan, then the associated FA section and costs will be updated. Changes with written estimates under PE seal will be submitted to the UIC Director within 60 days.

If there are no changes, Milestone will submit a letter stating that no changes are needed at this time, except for inflation adjustments.

If the UIC Director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, or emergency and remedial response. Milestone will provide to the UIC Director, within 60 days of notification by the Director, with a revised cost estimate under PE seal. Milestone will then adjust the amount of the Financial Assurance instruments within 60 days of approval of the new estimate by the UIC Director.

11.10.1 Inflation Adjustments

Milestone will automatically adjust the FA instruments for inflation based on CPI tables for the preceding calendar year. This adjustment will be included in the annual update.

11.11 Duration

Milestone will maintain adequate FA instruments and renew instruments for the entire duration of the geologic sequestration project until the UIC Director receives and approves a completed post-injection site care and site closure plan and approves the site closure plan.

Milestone may request release of FA obligations if it has completed a phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the UIC Director.

11.12 Third Party Instruments

When using a third-party instrument to demonstrate financial responsibility, Milestone will provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this FA section will be a corporate surety authorized to do business in Texas. The issuer's name address and evidence of authority to issue bonds in Texas have been provided as an FA appendix item.

11.13 Increases or Decreases

The UIC Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, Milestone will revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan, the injection well plugging plan, the post-injection site care and site closure plan, and the emergency and response plan, if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate will be adjusted for inflation (**Section 11.10.1**).

Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, Milestone, within 60 days after the increase, will 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 financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.

After the injection period of the project terminates, and the post-injection period begins, Milestone may apply for a reduction in the FA requirements required for post-injection site care and monitoring based on current monitoring results. It will be at the UIC Directors discretion whether to approve or deny the reduction.

Milestone will maintain the previously approved required Financial Assurance amounts until the new amount is approved by the UIC Director.

11.14 Adverse Financial Conditions

Milestone will notify the UIC Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.

Milestone will also notify the UIC Director of any third-party financial instrument providers that are going through bankruptcy or incapacity or any unforeseen event that would result in inability for the bond provider to do business in the state of Texas by certified mail. Milestone will notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming Milestone as debtor, within 10 days after commencement of the proceeding.

If due to incapacity by third party financial institutions such as surety bond companies, the UIC Director deems Milestone to be “without bond coverage” and issues an official notice to that effect, Milestone will respond to the UIC Director with a proposed plan to find a replacement provider and a reasonable period to replace bond coverage within 60 days of the notice. If the UIC Director specifies the period in the official notice, Milestone will still respond with a plan to find a replacement provider within 60 days.

11.15 Injection Fees and Post Injection Regulatory Fees [16 Texas Admin Code § 5.205 (A)]

Milestone will remit the required fees to the Comptroller of the State of Texas as stipulated in 16 Texas Admin Code § 5.205(A). Milestone will remit an initial permit application fee of $50,000 for a geologic storage facility. Milestone will remit an annual fee of $0.025 per metric ton of CO2 injected at the geologic storage facility. Further Milestone will remit an annual fee of $50,000 each year that Milestone does not inject any injectate into the geologic storage facility until the UIC Director has authorized storage facility closure.

Only the annual fee of $50,000 during the post-injection site care period has been included in the Monte Carlo analysis and the third-party estimate. A total of $2.5 Million, for fifty (50) years of post-injection site care, has been added as a line-item cost to the post-injection site care cost estimate. The initial application fee is paid at the time of application submission, and is therefore not necessary to assure, and the injection fee of $0.025 per metric ton will be remitted based on actual well results and remitted to the Comptroller of Texas concurrently with the annual report that is submitted to the UIC Director.

11.16 Protective Conditions [16 Texas Admin Code § 5.205 (D)(III)]

As noted previously, the surety bond will have certain protective conditions.

The surety bond will contain protective conditions of coverage. Protective conditions of coverage will include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

11.16.1 Cancellation

Milestone will provide that the surety bond may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation will not be final until at least 120 days after the Commission receives the cancellation notice. In that event Milestone will provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled will be released within 60 days of notification by the director.

11.16.2 Renewal

If the surety bond expires, Milestone will renew the previous instrument or contract a new financial instrument of sufficient value prior to the expiration date. Milestone will hold a FA instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as Milestone has the option of renewal at the face amount of the expiring instrument. The form of bond filed by Milestone will be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.

11.16.3 Remain in Effect

The surety bond shall remain in effect and cannot be canceled, terminated, or left unrenewed if, on or before its expiration date, any of the following conditions occur: the director deems the facility abandoned; the permit is terminated, revoked, or a new permit is denied; closure is ordered by the director, a United States district court, or another court of competent jurisdiction; the owner or operator becomes a debtor in a voluntary or involuntary bankruptcy proceeding under Title 11 of the U.S. Code; or the amount due is paid.

11.17 Summary

Milestone will employ surety bonds to meet Financial Assurance requirements. Milestone proposes a total FA cost of **$20,957,610** for the South Midland Facility. The entire amount will be provided by a surety bond.

To determine FA cost estimates subject to forecasting uncertainties, Milestone employed an EPA Class VI operations-tailored Monte Carlo simulation. This iterative costs-scenario approach generated a distributed range of possible FA estimates through simulations using 250,000 iterations addressing 74 activities inputs related to FA costs. This stochastically-modeled method enables us to assess the probabilities of specific events - that include worst case scenarios - and provides a comprehensive range of potential FA numbers. Consequently, Monte Carlo simulation offers a detailed understanding of the financial assurance requirements, accounting for various uncertainties and helping to make informed financial decisions.

Milestone will comply with all state and federal regulations for financial responsibility regarding the geologic sequestration project.